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SECTION 14

TRANSMISSION SYSTEMS

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14.1 OVERHEAD AC POWER TRANSMISSION

Overhead transmission of electric power remains one of the most important elements of today's electric power system. Transmission systems deliver power from generating plants to industrial sites and to substations from which distribution systems supply residential and commercial service. Those transmission systems also interconnect electric utilities, permitting power exchange when it is of economic advantage and to assist one another when generating plants are out of service because of damage or routine repairs. Total investment in transmission and substations is approximately 10% of the investment in generation.

Since the beginning of the electrical industry, research has been directed toward higher and higher voltages for transmission. As systems have grown, higher-voltage systems have rarely displaced existing systems, but have instead overlaid them. Economics have typically dictated that an overlay voltage should be between 2 and 3 times the voltage of the system it is reinforcing. Thus, it is common to see, for example, one system using lines rated 115, 230, and 500 kilovolts (kV). The highest ac voltage in commercial use is 765 kV although 1100 kV lines have seen limited use in Japan and Russia. Research and test lines have explored voltages as high as 1500 kV, but it is unlikely that, in the foreseeable future, use will be made of voltages higher than those already in service. This plateau in growth is due to a corresponding plateau in the size of generators and power plants, more homogeneity in the geographic pattern of power plants and loads, and adverse public reaction to overhead lines. Recognizing this plateau, some focus has been placed on making intermediate voltage lines more compact. Important advances in design of transmission structures as well as in the components used in line construction, particularly insulators, were made during the mid-1980s to mid-1990s. Current research promises some further improvements in lines of existing voltage including upgrading and now designs for HVDC.

14.1.1 Transmission Systems

The fundamental purpose of the electric utility transmission system is to transmit power from generating units to the distribution system that ultimately supplies the loads. This objective is served by transmission lines that connect the generators into the transmission network, interconnect various areas of the transmission network, interconnect one electric utility with another, or deliver the

TABLE 14-1 Standard System Voltages, kV

Rating		Rating	
Nominal	Maximum	Nominal	Maximum
34.5	36.5	230	242
46	48.3	345	362
69	72.5	500	550
115	121	765	800
138	145	1100	1200
161	169		

electrical power from various areas within the transmission network to the distribution substations. Transmission system design is the selection of the necessary lines and equipment which will deliver the required power and quality of service for the lowest overall average cost over the service life. The system must also be capable of expansion with minimum changes to existing facilities.

Electrical design of ac systems involves (1) power flow requirements; (2) system stability and dynamic performance; (3) selection of voltage level; (4) voltage and reactive power flow control; (5) conductor selection; (6) losses; (7) corona-related performance (radio, audible, and television noise); (8) electromagnetic field effects; (9) insulation and overvoltage design; (10) switching arrangements; (11) circuit-breaker duties; and (12) protective relaying.

Mechanical design includes (1) sag and tension calculations; (2) conductor composition; (3) conductor spacing (minimum spacing to be determined under electrical design); (4) types of insulators; and (5) selection of conductor hardware.

Structural design includes (1) selection of the type of structures to be used; (2) mechanical loading calculations; (3) foundations; and (4) guys and anchors.

Miscellaneous features of transmission-line design are (1) line location; (2) acquisition of right-of-way; (3) profiling; (4) locating structures; (5) inductive coordination (considers line location and electrical calculations); (6) means of communication; and (7) seismic factors.

14.1.2 Voltage Levels

Standard transmission voltages are established in the United States by the American National Standards Institute (ANSI). There is no clear delineation between distribution, subtransmission, and transmission voltage levels. In some systems 69 kV may be a transmission voltage while in other systems it is classified as distribution, depending on function. Table 14-1 shows the standard voltages listed in ANSI Standards C84 and C92.2, all of which are in use at present.

The nominal system voltages of 345, 500, and 765 kV from Table 14-1 are classified as extrahigh voltages (EHV). They are used extensively in the United States and in certain other parts of the world. In addition, 400-kV EHV transmission is used, principally in Europe. EHV is used for the transmission of large blocks of power and for longer distances than would be economically feasible at the lower voltages. EHV may be used also for interconnections between systems or superimposed on large power-system networks to transfer large blocks of power from one area to another.

One voltage level above 800 kV, namely, 1100 kV nominal (1200 kV maximum), is presently standardized. This level is not widely, although sufficient research and development have been completed to prove technical practicability.^{*1-3}

14.1.3 Conductor Selection

Considerations in Selection.⁴ The choice of a conductor for a transmission line, as with structure type, depends on the specific application. Once the mechanical strength requirement of the conductor

*Superscript numbers refer to references listed at the end of this section (*1-3).

is satisfied, the conductor choice considers the total costs associated with the conductor and also the corona-related electrical environmental effects of radio and audible noise. Corona also causes power loss, particularly during wet weather.

The electrical stress on the surface of a conductor is a function of the voltage on the conductor, the size (i.e., surface area) of a conductor, and the spacing between conductors and/or grounded objects.

The equivalent size of a conductor can be increased by using either a larger conductor or several smaller conductors electrically and physically connected together (bundled conductors). While a single, very large conductor would be electrically adequate, several smaller conductors offer practicality of manufacturing and transporting, ease of construction, and minimizing material usage and mechanical stresses on the supporting structures during high winds and/or ice on the conductors.

At voltages of 345 kV and above, the minimum conductor size or the minimum number of conductors and the individual conductor size in a bundle are, in addition to cost considerations, normally determined by the corona-related electrical environmental effects. At voltages below 345 kV (e.g., 69 through 230 kV), the minimum size is normally based only on conductor economics.

The conductor sag in the span between structures will depend on conductor materials, conductor weight, conductor strength, conductor tension, conductor temperature, and ice accumulation on the conductor. Strong conductors can be installed at higher tensions and will sag less.

As the current in a conductor increases, the losses increase with a resultant increase in conductor temperature, causing the sag to increase. If the conductor is carrying heavy electrical load on a hot day, very significant increases in sag can occur. Short spans of 150 to 300 ft may have sags of 2 to 5 ft. Long spans of 1000 to 1500 ft may experience sags of 40 ft or more.

Since a limiting design criterion is minimum conductor height above ground (for safety reasons), the maximum sags during operation can determine structure heights and span lengths. Similarly, in certain areas ice can form on the conductors of sufficient weight to limit the structure heights and span lengths to maintain ground clearance.

Economics. Conductor economic analyses normally use the present worth of revenue required (PWRR) method. This considers the sum of the present worth of levelized annual fixed charges on the total line capital investment, plus annual expenses for line losses:

$$\text{PWRR} = \sum_{n=1}^{\text{NYE}} \left(1 + \frac{i}{100} \right)^{-n} \times \left(\text{CI} \times \frac{F_L}{100} + \text{ADC}_n + \text{AEC}_n \right) \quad (14-1)$$

where PWRR = present worth of revenue required

NYE = number of years to be studied

n = n th year

i = annual discount rate in percent

CI = total per mile capital investment

F_L = line fixed-charge rate in percent

ADC_n = per mile demand charge for line losses for year n

AEC_n = per mile energy charge for line losses for year n

The cost of line losses is based on the cost of generating the losses. Annual demand and energy charges are calculated as shown in the following equations.

Annual demand charge for line losses for year n :

$$\text{ADC}_n = \frac{C_{\text{kW}} \times \text{ESC}_n}{10^3} \times \frac{F_g}{100} \times \left[1 + \frac{\text{RES}}{100} \times I_L^2 \times \frac{R}{N_c} \times N_{\text{ckt}} \times N_p \right] \quad (14-2)$$

where ADC_n = annual demand charge for year n

C_{kW} = installed generation cost in dollars per kilowatt

ESC_n = escalation cost factor for year n

F_g = generation fixed-charge rate in percent

RES = required generation reserve in percent

$$\begin{aligned}
 I_L &= \text{demand phase current in amperes per circuit} \\
 R &= \text{single conductor resistance in ohms per mile} \\
 N_c &= \text{number of conductors per phase} \\
 N_{\text{ckt}} &= \text{number of circuits} \\
 N_p &= \text{number of phases}
 \end{aligned}$$

Annual energy charge for line losses for year n :

$$AEC_n = \frac{C_{\text{MWh}} \times \text{ESC}_n}{10^6} \times 8760 \times \frac{L_f}{100} \times I_L^2 \times \frac{R}{N_c} \times N_{\text{ckt}} \times N_p \quad (14-3)$$

where AEC_n = annual energy charges for year n

C_{MWh} = cost of generating energy in dollars per megawatthour

ESC_n = escalation cost factor for year n

L_f = loss factor for determining energy losses in percent

I_L = demand phase current in amperes per circuit

R = single conductor resistance in ohms per mile

N_c = number of conductors per phase

N_{ckt} = number of circuits

N_p = number of phases

As the conductor size increases, the installed cost increases, because of both the increased conductor cost and the stronger structures necessary to support the larger, heavier conductor and the attendant mechanical loading. The larger conductor cross section, however, results in lower resistance and therefore lower losses. If corona losses are considered, these are also reduced for larger conductors, assuming other dimensions (e.g., phase spacing) remain constant. Therefore, there will be an overall minimum cost at a specific conductor size, where installed cost forces the PWRR higher for large conductors and the cost of losses forces the PWRR higher for smaller conductors. This is conceptualized in Fig. 14-1. In most practical analyses, there is a relatively flat “minimum” total cost (PWRR) region such that the line designer can temper the economic choice with other factors. Various conductor designs and configurations, such as number of conductors per bundle and size of conductors in a bundle, are examples of areas of designer preference. The higher cost of energy, primarily due to increased fuel costs, has increased the significance of cost of losses in the economic analysis, skewing the economics toward larger conductors with lower losses.

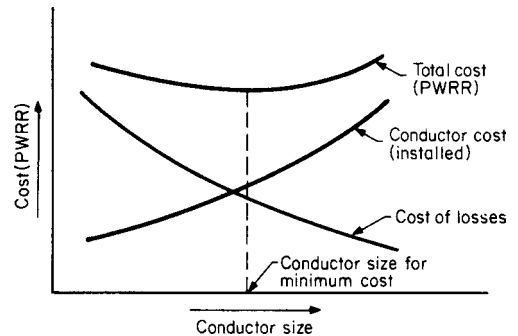


FIGURE 14-1 Conductor economic concept.

Beside the cost of electrical losses, the choice of conductor is an important factor in determining the maximum allowable power flow through the line. For long lines, maximum allowable power flow may be determined by limits on electrical phase shift or voltage drop. For shorter lines, the maximum conductor temperature (thermal rating) may limit the maximum allowable power flow. High thermal capacity can be accomplished either by using a large diameter conductor with relatively low electrical resistance or by using a conductor of relatively smaller diameter tolerant to high operating temperatures, such as ACSS conductors, which can operate continuously at 200°C with no changes in their mechanical properties. For example, consider the following thermal ratings calculated for a transmission line located in an environment with air temperature of 40°C, full sun, and a perpendicular wind speed of 2 ft/s.

Conductor name	Aluminum area (kcmil)	Maximum temperature ($^{\circ}\text{C}$)	Thermal rating (amperes)
Ibis	397.5	100	640
Drake	795	100	995
Falcon	1590	100	1520
Drake/ACSS	795	200	1600

Calculations leading to optimization plots such as shown in Fig. 14-1 are usually done assuming a relatively simple line model consisting of a conductor in catenary between structures at a typical spacing.⁴ In this “typical span” model, the line is approximated as a series of structures that have the same height and spacing so that the conductor between them has the same sag and tension in all spans. Typical numbers of angle and dead-end structures are assumed per mile of line. Structure height is just sufficient to meet ground clearance, and structure cost is estimated based on this height, on phase spacing, and on typical transverse, vertical, and longitudinal loads for this span. Such a simple typical span model yields exact electrical losses, approximate structure costs, and is adequate for the exact calculation of radio noise, audible noise, and electric and magnetic fields.

Having used the “typical span” model to determine the range of conductor sizes which yield minimum total present worth cost of electrical losses and construction costs and adequately low environmental effects, the transmission-line design can be further optimized by considering a more realistic “terrain optimized” model of the line on actual or typical terrain. In such a study, the designer utilizes the availability of fast, efficient tower spotting algorithms to provide more exact structure cost estimates. Such studies have been described in Refs. 5 and 6.

Optimization of transmission designs using modern computer-based techniques allows the designer to consider variations in standard design constraints by modeling alternate designs having various design constraints on the same terrain. For example, transmission-line designs normally assume a standard unloaded conductor tension. Optimization studies might include evaluation of higher than standard conductor tensions in order to reduce conductor sag at high temperature. A “typical span” model may be used to evaluate the savings in structure height due to reduced sag and the increased cost of angle structures due to higher tension levels. A “terrain optimized” model will provide a more realistic estimate of the savings in structure height and the increased cost of angle structures and dead ends and will also identify costs related to uplift of structures at minimum temperature.

In addition to conductor tension, a “terrain optimized” model of the proposed line allows the designer to estimate costs for variations in

Available structure classes (e.g., fewer tangent types, an added light angle structure)

Conductor type (e.g., percentage of steel area in ACSR, self-damping conductor)

Available structure heights (e.g., fewer available heights, taller structures)

Optimization studies involve the consideration of nonstandard conductors and structures. This is typically justified only by large-scale design and construction projects or during the development of new standard transmission designs to meet changes in environmental effect constraints. Reuse of existing “standard” structure designs or conductors is often preferred due to considerations such as spare parts, tools and training, maintenance, known reliability, externally imposed factors such as hot line maintenance clearances, and short or highly constrained construction.

A highly variable component of transmission line costs is getting permits and rights-of-way. In some extreme situations this may be so great as to counter balance the normally much higher cost of underground cables.

14.1.4 Electrical Properties of Conductors

Positive-Sequence Resistance and Reactances. The conductors most commonly used for transmission lines have been aluminum conductor steel-reinforced (ACSR), all-aluminum conductor (AAC), all-aluminum alloy conductor (AAAC), and aluminum conductor alloy-reinforced (ACAR),

but conductors able to operate at higher temperatures such as ACSS are available for a modest price premium and are becoming more common. Research is progressing on new high temperature ceramic-cored conductors. Tables of the electrical characteristics of the most commonly used ACSR conductors are in Sec. 4. Characteristics of other conductors can be found in conductor handbooks or manufacturers' literature and web sites.

The per mile resistance, inductive reactance, and capacitive reactance can be determined from the data in the tables of Sec. 4 and the spacing factors X_d and X_d' .

The positive-sequence resistance is listed as the 60-Hz value at 50°C. The expression for inductive reactance per mile is

$$X_L = 0.004657f \log \frac{D}{\text{GMR}} \quad (14-4)$$

where D = equivalent spacing in feet, GMR = geometric mean radius in feet as given in the conductor tables of Sec. 4, and f = frequency in hertz. GMR for ACSR conductor is given at 60 Hz. However, 60-Hz values of GMR can be used at other commercial power-system frequencies with small error. X_L also can be expressed as

$$X_L = X_a + X_d = 0.004657f \log \frac{1}{\text{GMR}} + 0.004657f \log D \quad (14-5)$$

When the spacing is 1 ft, X_d becomes zero. Thus X_d is frequently called the "one-foot" inductive reactance. The expression for capacitive shunt reactance per mile is:

$$X_c = \frac{4.099 \times 10^6}{f} \log \frac{D}{r_c} \quad (14-6)$$

where r_c = conductor radius in feet, which can also be expressed as

$$X_c = X'_a + X'_d$$

where

$$X'_a = \frac{4.099 \times 10^6}{f} \log \frac{1}{r_c} \quad (14-7)$$

and

$$X'_d = \frac{4.099 \times 10^6}{f} \log D \quad (14-8)$$

Bundle conductors consist of two or more conductors per phase mechanically and electrically connected and supported by an insulator assembly. The positive-sequence resistance is, to a first approximation, the 60-Hz, 50°C values in the Sec. 4 tables divided by the number of conductors per phase. General formulas for the inductance and capacitance of bundle conductors are

$$L_\phi = \frac{1}{n} \left[0.74113 \log \frac{r_c}{\text{GMR}} + 0.74113 \log \frac{24(S_{gm})^n}{d(M_{gm})^{n-1}} \right] \text{ mH/mi} \quad (14-9)$$

From Eq. (14-9) inductive reactance is found to be

$$X_L = \frac{1}{n} \left[K + 0.004657f \log \frac{24(S_{gm})^n}{d(M_{gm})^{n-1}} \right] \quad \Omega/\text{mi at 60 Hz} \quad (14-10)$$

and the capacitance is

$$C_\phi = \frac{0.03883n}{\log[24(S_{gm})^n/d(M_{gm})^{n-1}]} \quad \mu\text{F/mi} \quad (14-11)$$

In the above, n = number of conductors per phase (bundle); d = diameter of conductor in inches; S_{gm} = geometric mean distance between conductors of different phases in feet, found by taking the

mean distance from all conductors of one phase to all conductors of the other phases; M_{gm} = geometric mean distance in feet between the n conductors of one phase; K = internal conductor reactance defined as

$$K = 0.004657f \log \frac{r_c}{\text{GMR}} \quad \Omega/\text{mi} \quad (14-12)$$

TABLE 14-2 Equivalent Reactances

Bundle	X_{aeq}	X'_{aeq}
2 conductors	$\frac{1}{2}(X_a - X_s)$	$\frac{1}{2}(X'_a - X'_s)$
3 conductors	$\frac{1}{3}(X_a - 2X_s)$	$\frac{1}{3}(X'_a - 2X'_s)$
4 conductors	$\frac{1}{4}(X_a - 3X_s)$	$\frac{1}{4}(X'_a - 3X'_s)$

The inductive series reactance and capacitive shunt reactances for bundled conductors can also be found by using the $X_a + X_d$ method, by determining the equivalent X_a and X'_a of the conductor bundle. The expressions for the equivalents are given in Table 14-2. These expressions are for three-conductor bundles on equilateral spacing and for four-conductor bundles on square spacing. The subscript s indicates the spacing of the conductors within the bundle in feet. Values for X_a and X'_a are in the conductor tables in Sec. 4. Values for X_s and X'_s are from the same formulas as X_d and X'_d .

$$X_s = 0.004657f \log s \quad (14-13)$$

$$X'_s = \frac{4.099 \times 10^8}{f} \log s \quad (14-14)$$

where s is in feet and f is frequency in hertz. Equation (14-14) is correct for a ratio of spacing s to conductor radius r of 5 or more.

The value of X_{aeq} is added to X_d (the spacing factor, which is determined for the mean spacing between the conductors of the different phases). X'_{aeq} and X'_d are handled in a like manner.

Zero-Sequence Impedances. When earth-return currents due to faults or other causes are to be calculated, negative- and zero-sequence impedances must be determined in addition to positive-sequence quantities. Negative-sequence quantities are the same as the positive-sequence values for transmission lines. Precise determination of the zero-sequence quantities is difficult because of the variability of the earth-return path.

Calculation of zero-sequence impedance parameters is far more complex than for positive-sequence quantities, being a function of conductor size, spacing, relative position of conductors with respect to overhead ground wires, electrical characteristics of overhead ground wires, and the resistivity of the earth-return circuit. Reference 7 includes a detailed analysis of zero-sequence parameters, which are normally calculated using digital computer programs.

Table 14-3 lists representative values of positive- and zero-sequence impedances for different voltage transmission lines with shield wires. Zero-sequence reactance increases for unshielded lines.

TABLE 14-3 Typical Transmission-Line Impedance*

Voltage, kV	R_1	X_{L1}	X_{C1}	R_0	X_{L0}	X_{C0}	X_0/X_1
69	0.280	0.709	0.166	0.687	2.74	0.315	3.86
115	0.119	0.723	0.169	0.625	2.45	0.265	3.39
230	0.100	0.777	0.182	0.591	2.26	0.275	2.91
345	0.060	0.590	0.138	0.551	1.99	0.208	3.37
500	0.028	0.543	0.127	0.463	1.90	0.198	3.50
765	0.019	0.548	0.128	0.428	1.77	0.185	3.23

* R_1 , X_{L1} , R_0 , X_{L0} are in ohms per mile; X_{C0} , X_{C1} are in megohm-miles.

Note: 1 mi = 1.61 km.

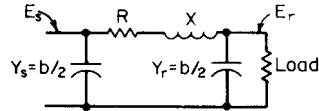
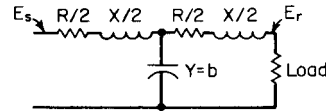
FIGURE 14-2 Nominal- π line.

FIGURE 14-3 Nominal-T line.

Nominal- π Representation. Transmission lines can be represented by nominal π as in Fig. 14-2, in which half the capacitive susceptance, in siemens, is connected at each end of the line. The nominal- π representation is used in digital computer studies involving lines of moderate length (usually under 100 mi).

Nominal-T Representation. The nominal-T representation of a transmission line is shown in Fig. 14-3. The total line susceptance b , in siemens, is concentrated at A , the midpoint of the line.

ABCD Parameters. These line parameters (general circuit constants) are defined by the equations

$$E_s = AE_r - BI_r \quad (14-15)$$

$$I_s = CE_r - DI_r \quad (14-16)$$

For a short line (under 100 mi) if $Z_1 = R + j\omega L$ and $Z_2 = 2/jb$ (refer to the nominal- π line of Fig. 14-2)

$$A = D = \frac{Z_1 + Z_2}{Z_2} \quad (14-17)$$

$$B = Z_1 l \quad (14-18)$$

$$C = \left(\frac{Z_1 + 2Z_2}{Z_2^2} \right) l \quad (14-19)$$

For longer lines where l is the length of the line

$$A = D = \cosh(\gamma l) \quad (14-20)$$

$$B = Z_c \sinh(\gamma l) \quad (14-21)$$

$$C = \frac{\sinh(\gamma l)}{Z_c} \quad (14-22)$$

where

$$\gamma = \sqrt{(R + j\omega L)(j\omega C)} \quad (14-23)$$

and

$$Z_c = \sqrt{\frac{R + j\omega L}{j\omega C}} \quad (14-24)$$

and R , L , and C are line resistance, inductance, and capacitance per mile.

Formulas for $ABCD$ constants for various circuit configurations are given in Table 14-4.

Surge Impedance Loading. The surge impedance of a transmission line is the characteristic impedance with resistance set equal to zero (i.e., R is assumed small compared to $j\omega L$ of Eq. 14-24).

$$Z_s = \sqrt{\frac{L}{C}} \quad (14-25)$$

TABLE 14-4 Formulas for Generalized Circuit Constants

No.	Type of network		Equivalent constants			
			A_t	B_t	C_E	D_t
1	Series impedance		1	Z	O	1
2	Shunt admittance		1	O	Y	1
3	Uniform line		A	B	C	A
4	Two uniform lines		$A_1A_2 + C_1B_2$	$B_1A_2 + A_1B_2$	$A_1C_2 + A_2C_1$	$A_1A_2 + B_1C_2$
5	Two nonuniform lines or networks		$A_1A_2 + C_1B_2$	$B_1A_2 + D_1B_2$	$A_1C_2 + D_2C_1$	$D_1D_2 + B_1C_2$
6	General network and sending transformer impedance		$A + CZ_{TS}$	$B + DZ_{TS}$	C	D
7	General network and receiving transformer impedance		A	$B + AZ_{TR}$	C	$D + CZ_{TR}$
8	Two networks in parallel		$\frac{A_1B_2 + A_2B_1}{B_1 + B_2}$	$\frac{B_1B_2}{B_1 + B_2} + \frac{(A_1 - A_2)(D_2 - D_1)}{B_1 + B_2}$	$\frac{D_1B_2 + D_2B_1}{B_1 + B_2}$	

Note: All constants in this table are complex quantities; $A = a_1 + ja_2$ and $D = d_1 + jd_2$ are numerical values, $B = b_1 + jb_2 = \text{ohms}$, and $C = c_1 + jc_2 = \text{siemens}$. As a check on calculations of $ABCD$ constants, note that $AD - BC = 1$.

The power which flows in a lossless transmission line terminated in a resistive load equal to the line's surge impedance is denoted as the surge impedance loading (SIL) of the line. Under these conditions, the receiving end voltage E_R equals the sending end voltage E_S in the magnitude, but lags E_S by an angle δ corresponding to the travel time of the line. For a 3-phase line

$$\text{SIL} = \frac{(E_{L-L})^2}{Z_s} \quad (14-26)$$

Since Z_s has no reactive component, there is no reactive power in the line, $Q_s = Q_R = 0$. This indicates that for SIL the reactive losses in the line inductance are exactly offset by reactive power supplied by the shunt capacitance or $P\omega L = E^2\omega C$.

SIL is a useful measure of transmission-line capability even for practical lines with resistance, as it indicates a loading where the line's reactive requirements are small. For power transfer significantly above SIL, shunt capacitors may be needed to minimize voltage drop along the line, while for transfer significantly below SIL, shunt reactors may be needed.

SILs for typical transmission lines are given in Table 14-5. Cables normally have current ratings (ampacity) considerably below SIL, while overhead line current ratings may be either greater than or less than SIL. Figure 14-4 presents illustrative overhead line loadability as a function of line length and SIL.

Although Fig. 14-4 is illustrative only of loading limits, it is a useful estimating tool. Long lines tend to be stability-limited and have a lower loading limit than shorter lines, which tend to be voltage-drop- or conductor-ampacity-limited.

TABLE 14-5 SIL of Typical Transmission Lines

System kV	Z_s, Ω	SIL, MW
Overhead lines		
230	367	144
345	300	400
500	285	880
65	280	2090
1200	250	5760
Cables		
230	38	1390
345	25	4760

14.1.5 Electrical Environmental Effects

Corona and Field Effects. There are two categories of electrical environmental effects of power transmission lines. Corona effects are those caused by electrical stresses at the conductor surface which result in air ionization (“corona”) and include radio, television, and audible noise. Field effects are those caused by induction to objects in proximity to the line. While the generic term is electromagnetic effects, within the electric power industry the fields are divided into two types: electric-field effects and magnetic-field effects. Electric fields, related to the voltage of the line, are the primary cause of induction to vehicles, buildings, and objects of comparable size. Magnetic fields, related to the currents in the line, are the primary cause of induction to long objects, such as fences and pipelines.

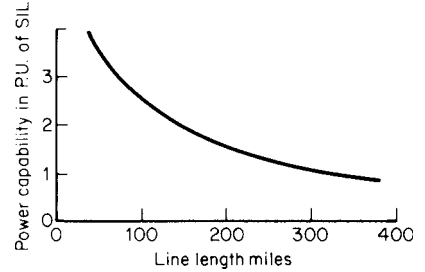


FIGURE 14-4 Overhead line loading in terms of SIL.

Assessment Criteria. In an electrical environmental analysis, it is important to determine the proper criteria for assessment of the impact. For example, the audible noise criterion in a commercial or industrial area would be inappropriate in a quiet residential neighborhood.⁸ Likewise, ground-level electric field criteria on a parking lot would be different from that in terrain inaccessible by motor vehicles. For audible noise, the only concern is annoyance, but for electric fields, safety, annoyance, and perception levels all may have to be considered.

Probability of exposure is also an important criterion. The impact of radio noise in arid locations is different from that in places with considerable rainfall. Since different people have different perception and annoyance thresholds, statistical evaluations are necessary, recognizing that some percentage of people will find a generally accepted noise level annoying. Because of the combination of worst-case events which are normally assumed in an electrical environmental analysis, the overall probability of annoyance is usually considerably smaller than initially presumed.

A predictive model is necessary to calculate the expected effect. Depending on the specific effect, it may be an empirical formula or may be quite sophisticated. However, it is only by calculating the effect and comparing it with specified criteria that the overall impact can be assessed. This is illustrated by Fig. 14-5,⁹ which is a flowchart of the analysis procedure for an example case of electric-field-induced shock.

Audible Noise. Corona-produced audible noise during foul weather, particularly during or following rain, can be an important design parameter for high-voltage ac transmission lines. Audible noise has two components, a random noise component and a low-frequency hum, each produced by different physical mechanisms. While the hum component is closely correlated with corona loss on the line, the random noise is not. Of these two, the most frequent cause of annoyance is the random noise, and it is this which is calculated and compared with acceptance criteria.

Analyses to predict levels of audible noise consider A-weighted sound level [dB(A)] during rain, including

L_{50} , which is the level exceeded 50% of the time during rain (considering all rain storms over a period of time, usually 1 year).

L_5 , which is the level exceeded 5% of the time during rain.

Average, which is the average level of noise expected during rain. (This is usually close to the L_{50} value and is sometimes called “wet-conductor” noise.)

Heavy rain, which is the level expected during heavy rain. (This usually is representative of laboratory artificial rain tests but is assumed representative of the L_5 level.)

Reference 10 compares audible noise formulas, which have been developed throughout the world. One formula for both L_5 and L_{50} values is given by

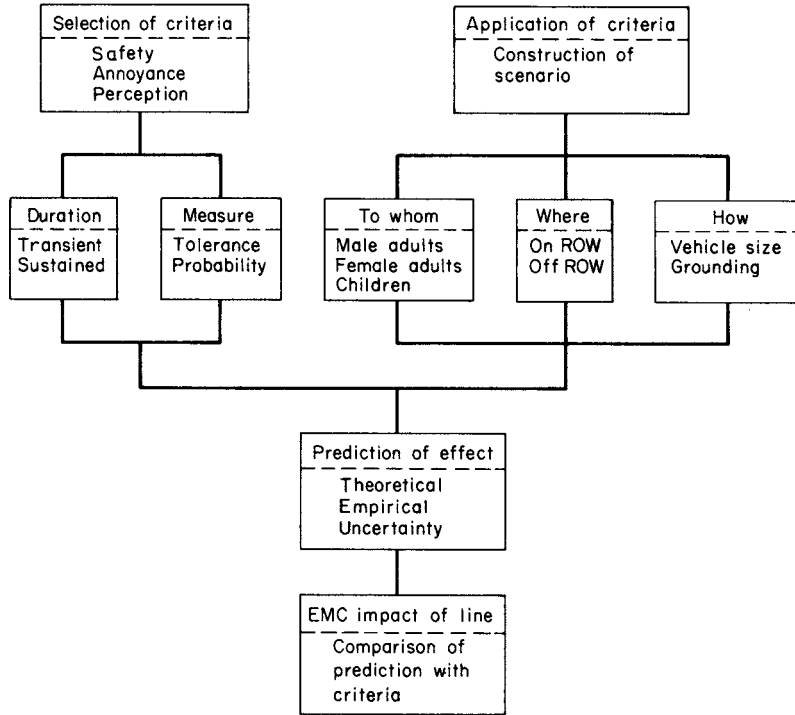


FIGURE 14-5 Factors affecting transmission line EMC for shock effects.

- g = Average-maximum surface gradient of conductor or conductor bundle, kV/cm
 n = Number of subconductors in a phase (or pole) bundle
 d = Diameter of subconductors, cm
 D = Distance from line to point at which noise level is to be calculated, m
 SL = A-weighted sound level of the noise produced by the line, dB(A)
 N_p = number of phases
- AN = A-weighted sound level of the noise produced by one phase of the line, dB(A)
 AN_0 = A reference A-weighted sound level, dB(A)
 K_1, K_2, K_3, K_4 = Constant coefficients
 Application = All line geometries
 Noise measure = L_5 rain and L_{50} rain
 Range of validity = 230–1500 kV, $1 \leq n \leq 16$, $2 \leq d \leq 6$

For each phase, the L_5 noise level is given by

$$AN_5 = \frac{-665}{g} + 20 \log n + 44 \log d - 10 \log D - 0.02 D + AN_0 + K_1 + K_2 \quad (14-27)$$

with

$$\begin{aligned}
 AN_0 &= 75.2 & \text{for } n < 3 \\
 &= 67.9 & \text{for } n \geq 3 \\
 K_1 &= 7.5 & \text{for } n = 1 \\
 &= 2.6 & \text{for } n = 2
 \end{aligned}$$

$$\begin{aligned}
 &= 0 && \text{for } n \geq 3 \\
 K_2 &= 0 && \text{for } n < 3 \\
 &= 22.9(n-1) \frac{d}{B} && \text{for } n \geq 3
 \end{aligned}$$

where B is the bundle diameter, cm.

The L_{50} level for each phase is obtained from

$$AN_{50} = AN_5 - \Delta A \quad (14-28)$$

where

$$\begin{aligned}
 \Delta A &= 14.2 \frac{g_c}{g} - 8.2 && \text{for } n < 3 \\
 &= 14.2 \frac{g_c}{g} - 10.4 - 8 \left[(n-1) \frac{d}{B} \right] && \text{for } n > 3
 \end{aligned}$$

and

$$\begin{aligned}
 g_c &= 24.4 (d^{-0.24}) && \text{for } n \leq 8 \\
 &= 24.4 (d^{-0.24}) - 0.25 (n-8) && \text{for } n > 8 \\
 SL &= 10 \log \sum_{i=1}^{N_p} 10^{AN_i/10} && (14-29)
 \end{aligned}$$

Figure 14-6 illustrates a typical presentation of audible noise calculations. The profile, in this case for a representative 500-kV line and wet conductors, quantifies the level of noise in dB(A) greater than 0.002 μ bar as a function of distance from the centerline of the structure. From this method of presentation, analysis of maximum levels as well as effect on width of right-of-way can be analyzed. Similarly, design variables such as conductor size, spacing, and configuration; height of conductors; and weather variations can be considered.

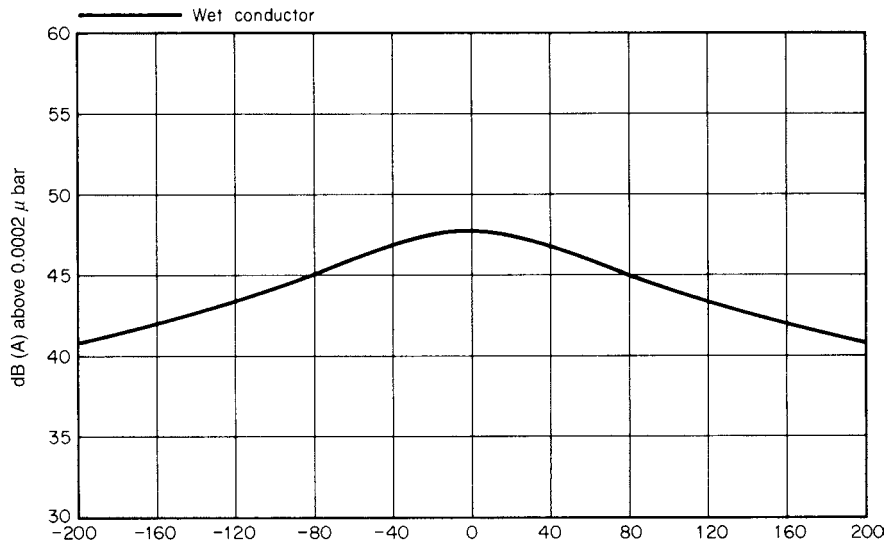


FIGURE 14-6 Audible noise profile at ground level for a transmission line.

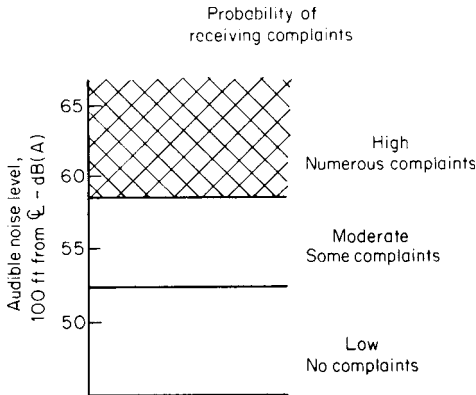


FIGURE 14-7 Audible noise compliance guidelines.

Figure 14-7^{3,11} quantifies experience with transmission-line audible noise complaints. These occur mostly during wet-conductor conditions and low ambient noise, such as after rain or during fog. During heavy-rain conditions, the noise of the rain masks the line noise. Other factors during heavy rain, such as closed windows, combine to make this condition less likely to result in complaints even though the noise is louder. In the absence of local noise regulations, comparison of calculated L_{50} or average audible noise with Fig. 14-7 gives a reasonable preliminary evaluation of the possibility of audible noise annoyance. When measurements are to be taken to confirm ambient noise or line noise, care must be taken to follow proper procedures.¹²

Radio and Television Noise. Electromagnetic interference from overhead power lines is caused by two phenomena: complete electrical discharges across small gaps (microsparks) and partial electrical discharges (corona). Gap-type sources occur at insulators, line hardware, and defective equipment and are a construction and maintenance problem rather than a design consideration. They are responsible for about 90% of radio noise complaints and can be located and eliminated as they occur.¹³ Conductor and hardware corona is considered during the design phase. On a properly designed line, conductor corona noise rarely results in television interference complaints except perhaps in weak signal fringe areas.

The specification of “corona-free” hardware is important to eliminate electromagnetic interference from conductor support hardware, and is especially important as lines are constructed with closer spacings and resulting higher electric fields on the hardware. Conductor clamps and other fittings, which were formerly acceptable at traditional phase spacings, may not be adequate for compact lines.

For ac lines, radio and television noise are functions of the weather. Fair-weather noise may be significant and varies with the season, wind velocity, and barometric pressure.

Two families of computation methods are available for radio noise: those based on conductor laboratory tests and analytical propagation theory (semianalytical methods) and those based on an empirical formula using data from long-term tests on operating lines (comparative methods).

The comparison method¹⁴ is useful for conventional geometries and designs:

$$RI = -150.4 + 120 \log g + 40 \log d + 20 \log \frac{h}{D^2} + 10 [1 - (\log 10f)^2] \quad (14-30)$$

where g = average maximum surface gradient of conductor or conductor-bundle, kV peak/cm

d = subconductor diameter, mm

h = height of phase, m

D = radial distance to observer, m

f = frequency, MHz

RI = fair-weather radio noise, dB

RI is calculated for each phase and the maximum value is used as the RI of the line. Average foul-weather RI levels are assumed to be 17 dB above fair weather, and heavy-rain RI 24 dB above fair weather. Other methods are described in Ref. 3.

As with audible noise, the most useful data presentation is the level of radio noise as a function of distance from the centerline of the structure. An illustrative example for a specific 500-kV line is shown in Fig. 14-8.

There are no generally accepted RI limits in the United States, because of the impossibility of setting universal criteria for all land use and local conditions.¹⁵ A Canadian standard exists for RI limits and is a useful guide.¹⁶

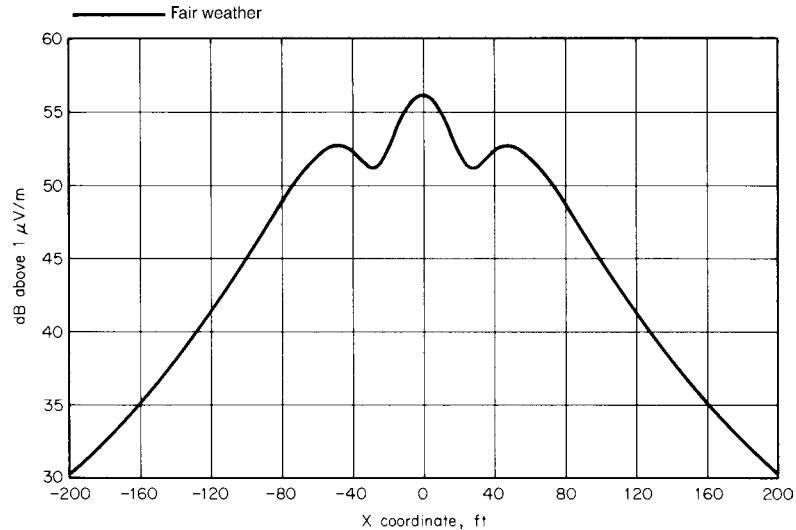


FIGURE 14-8 Radio noise profile at ground level for transmission line.

Two quantities are required to set criteria for evaluation of radio noise. These are the level of signal strength in the line vicinity and an appropriate signal/noise ratio. This latter ratio is typically assumed to be 24 to 26 dB at the edge of the right-of-way. Primary signal strengths may be 54 dB above 1 μ V (0.5 mV/m) in rural areas to 88 dB or more in cities.

Prediction of television noise is not as advanced as that of radio noise, primarily because of the limited number of actual cases of conductor corona television interference. As with radio noise, most television interference complaints result from microsparks which can be located and eliminated as they occur. These are not generally a design consideration. In the few cases where corona-caused television noise has occurred in foul weather, it has often been possible to remedy the situation by an improvement in the receiving antennas rather than changes to the transmission-line design. References 3 and 17 contain recent work on prediction and evaluation of TVI.

Gaseous Oxidants. Gaseous oxidants can be produced by corona activity in air and, in sufficient concentrations, may produce adverse effects on flora and fauna. The most important oxidants are ozone (O_3) and oxides of nitrogen (mainly NO and NO_2), where ozone is the major constituent.

Federal standards limit photochemical oxidants to 0.12 part per million for a maximum of 1-h concentration not to be exceeded more than once per year. Some states have more restrictive regulation; for example, the Minnesota Pollution Control Agency standards are for 0.07 ppm by volume ($130 \mu\text{g}/\text{m}^3$). Ozone can be detected by smell at minimum concentrations of 0.01 to 0.15 ppm.

Analytic studies and field measurements have been conducted on both operating and test lines.¹⁸⁻²⁵ The highest calculated value for 1-mi/h wind parallel to the line was 0.019 ppm maximum ground-level concentration. Measurements have indicated that transmission-line contribution to gaseous oxidants cannot be detected within statistical limits of significance and accuracy. With instrumentation capable of detecting 0.002 ppm, the transmission-line contribution was indistinguishable from ambient.

Thus, gaseous oxidants are not a concern with respect to electric power transmission lines.

Ground-Level Electric Fields. Ground-level electric field effects of overhead power transmission lines relate to the possibility of exposure to electric discharges from objects in the field of the line. These may be steady currents or spark discharges. Other areas which have received attention are the possibility of fuel ignition and interference with wearers of prosthetic devices (e.g., pacemakers).²⁶

It is appropriate to consider unlikely conditions when setting and applying electric-field safety criteria because of possible consequences; thus statistical considerations are necessary. Annoyance

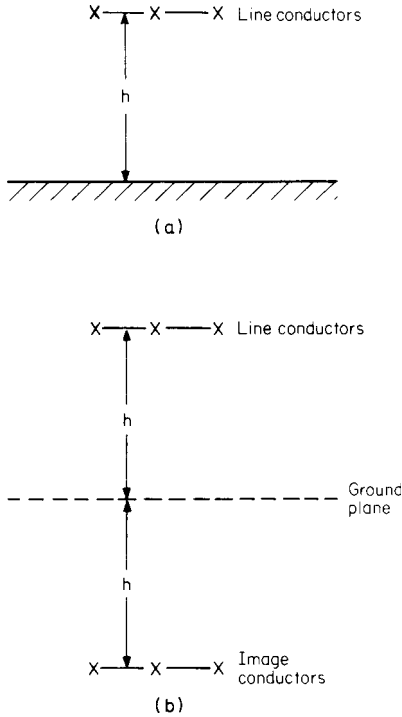


FIGURE 14-9 Representation of conducting earth: (a) earth; (b) image.

criteria need not be as stringent and mitigating factors can be considered.

Electric-Field Calculations. The resultant electric fields in proximity to a transmission line are the superposition of the fields due to the three-phase conductors. The conducting earth must be represented by image charges located below the conductors at a depth equal to the conductor height.

For example, consider the three-conductor line of Fig. 14-9. The effect of earth can be represented by replacing the earth with image conductors as shown in Fig. 14-9. At 60 Hz and for typical values of earth resistivity, the relaxation time of the earth (the time required for charges to redistribute themselves due to an externally applied field) is so small compared to the power frequency wave that for each instant of time the charge is distributed on the earth's surface as in the static condition (i.e., the earth appears to be a perfect conductor).

The electric fields surrounding the transmission line are a function of the instantaneous charges on the line. Usually, however, the charges are not known, but the voltages to ground of the different conductors are. Since the charge Q on each conductor is a function of the voltage on all conductors, an $n \times n$ capacitance matrix results, where n is the number of conductors, according to the formula

$$[Q] = [C][V] \quad (14-31)$$

which, for a three-conductor configuration (ignoring shield wires), is

$$Q_1 = C_{11} V_1 + C_{12} V_2 + C_{13} V_3 \quad (14-32)$$

$$Q_2 = C_{21} V_1 + C_{22} V_2 + C_{23} V_3 \quad (14-33)$$

$$Q_3 = C_{31} V_1 + C_{32} V_2 + C_{33} V_3 \quad (14-34)$$

The off-diagonal (mutual) capacitance terms significantly affect the final results. The individual terms of the capacitance matrix are computed by

$$C_{nm} = \left. \frac{Q_n}{V_m} \right|_{\text{all other voltages} = 0} \quad (14-35)$$

where n and m are conductors.

The potential coefficient matrix is, however, more amenable to computation and is defined by

$$[V] = [P][Q] \quad (14-36)$$

whose individual terms are given by

$$P_{nm} = \left. \frac{V_n}{Q_m} \right|_{\text{all other charges} = 0} \quad (14-37)$$

This is an open-circuit matrix where the individual terms can be computed by assuming a charge at one conductor and calculating the voltage at the prescribed location assuming all the other

conductors nonexistent (open-circuited). For a single conductor of radius r and a height h above the earth, the self-potential coefficient is given by

$$P_{nn} = \frac{1}{2\pi\epsilon_o} \ln \frac{2h}{r} \quad (14-38)$$

For two conductors n and m where d_{nm} is the distance between them, and $d_{nm'}$ is the distance between conductor n and the image of conductor m , the mutual potential coefficient is given by

$$P_{nm} = \frac{1}{2\pi\epsilon_o} \ln \frac{d_{nm'}}{d_{nm}} \quad (14-39)$$

This potential coefficient matrix can be calculated and inverted to yield the capacitance matrix:

$$[C] = [P]^{-1} \quad (14-40)$$

This capacitance matrix allows the calculation of the charges on the individual conductors for the given initial voltage distribution according to Eqs. (14-32) through (14-34). Once these charges are obtained, the desired electric fields can be determined.

For the single conductor and observer location of Fig. 14-10, the ground-level electric field is determined from

$$E = \frac{Q_l}{2\pi\epsilon_o r} \quad (14-41)$$

The distance from the conductor to the observer is

$$r = \sqrt{h^2 + L^2} \quad (14-42)$$

Thus

$$E = \frac{Q_l}{2\pi\epsilon_o \sqrt{h^2 + L^2}} \quad (14-43)$$

Q must be determined from $[Q] = [C][V]$. For a single conductor this equation reduces to

$$Q_l = P^{-1}V = \frac{1}{\frac{1}{(2\pi\epsilon_o)} \ln(2h/r)} V \quad (14-44)$$

For a multiconductor configuration, Q would come from the full matrix calculation.

E is radially directed from the line charge. The vertical component is

$$|E| \cos \theta = \frac{Q_l}{2\pi\epsilon_o \sqrt{h^2 + L^2}} \frac{h}{\sqrt{h^2 + L^2}} = \frac{Q_l}{2\pi\epsilon_o} \frac{h}{h^2 + L^2} \quad (14-45)$$

The vertical component of the electric field at ground level because of the image is equal to the field from the conductor, since the image is the geometric mirror image and has the opposite sign charge. Thus, the total ground-level field is given by

$$E = \frac{Q_l}{\pi\epsilon_o} \frac{h}{h^2 + L^2} \quad (14-46)$$

At ground level, the horizontal components of the electric fields of the conductor and its image cancel and the resultant field is purely vertical.

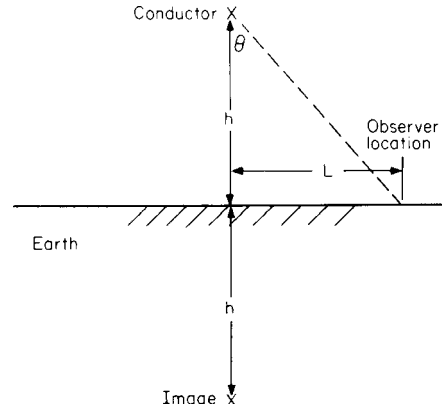


FIGURE 14-10 Single conductor.

For a 3-phase line, the fields of the three conductors and their images are computed separately and added.

For fields extremely close to the line conductors, care must be taken to represent the local effects properly. For example, the surface field around the conductor is not uniform. For a bundled conductor, it is more nearly represented by a sinusoid. Farther from the conductors, a GMR representation will suffice.

For a bundle of diameter D with n conductors of radius r , the GMR is given by

$$\text{GMR} = \frac{D}{2} \sqrt[n]{\frac{2nr}{D}} \quad (14-47)$$

Replacing the conductor radius with the bundle GMR gives the appropriate representation.

Figure 14-11 illustrates a representative electric-field profile, in kV rms per meter, from the centerline of the structure. This presentation clearly illustrates the maximum field, the location of the maximum, and the effect on right-of-way width considerations. Sensitivity to various parameters can also be quickly evaluated.

Criteria for Evaluation. The effects of electromagnetic fields on humans is due to discharges from objects insulated from ground; typically vehicles, buildings, and fences which become electrically charged by induction from the line. Table 14-6 summarizes effects on humans, ranging from no perception through severe shock and possible ventricular fibrillation.²⁷

Criteria for spark discharges are expressed in terms of stored charge or stored energy on the charged object. Levels for perception in adult males are of the order of 0.12 mJ, while experience indicates that approximately 2 mJ results in an annoying spark. Safety is seldom of concern, since approximately 25 J is required for injury, a value beyond that expected on objects beneath transmission lines.

Deno's work, using test data, relates short-circuit current to the undisturbed electric field for objects insulated from ground.²⁶ Initial calculations assume the worst possible combination of circumstances; no leakage path to ground exists for the object, complete grounding of the person involved, steady contact, and orientation of the vehicle parallel to the line. Table 14-7 lists sample criteria and electric fields needed to meet them for three sample vehicles.

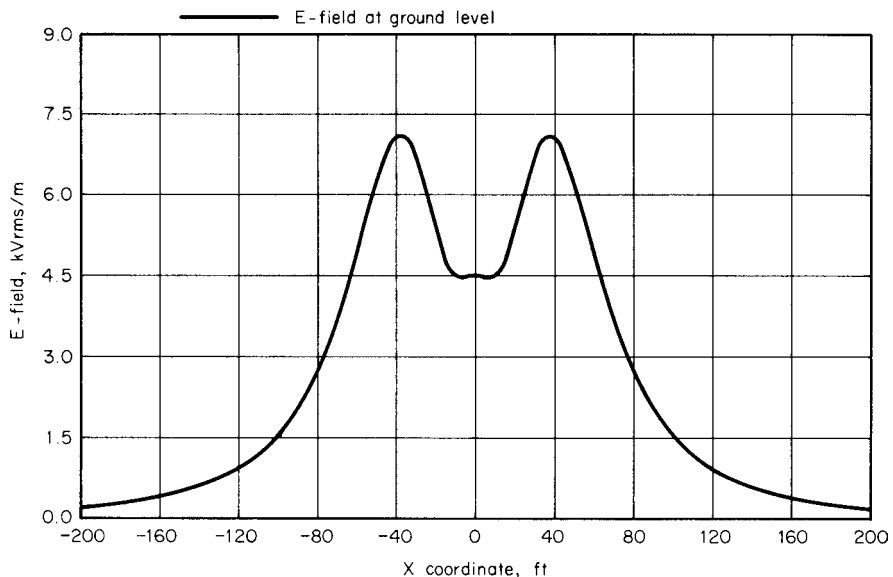


FIGURE 14-11 Electric-field profile at ground level for transmission line.

TABLE 14-6 Threshold Levels for 60-Hz Contact Currents

rms current, mA	Threshold reaction and/or sensation
Perception	
0.09	Touch perception for 1% of women
0.13	Touch perception for 1% of men
0.24	Touch perception for 50% of women
0.33	Grip perception for 1% of women
0.36	Touch perception for 50% of men
0.49	Grip perception for 1% of men
0.73	Grip perception for 50% of women
1.10	Grip perception for 50% of men
Startle	
2.2	Estimated borderline hazardous reaction, 50% probability for women (arm contact)
3.2	Estimated borderline hazardous reaction, 50% probability for women (pinched contacts)
Let-go	
4.5	Estimated let-go for 0.5% of children
6.0	Let-go for 0.5% of women
9.0	Let-go for 0.5% of men
10.5	Let-go for 50% of women
16.0	Let-go for 50% of men
Respiratory tetanus	
15	Breathing difficult for 50% of women
23	Breathing difficult for 50% of men
Fibrillation	
35	Estimated 3-s fibrillating current for 0.5% of 20-kg (44-lb) children
100	Estimated 3-s fibrillating current for 0.5% of 70-kg (150-lb) adults
Established standards	
0.50	ANSI standard for maximum leakage (portable appliance)
0.75	ANSI standard for maximum leakage (installed appliance)
5.0	NESC recommended limit for induced current under transmission line

TABLE 14-7 Limiting Electric Field for Given Criteria, kV/m

Sample criteria		Sample vehicles		
		Autos, pickups	Farm vehicles	Buses, trailer trucks
		A	B	C
Safety	5 mA	22.32	10.86	6.33
	25 J	259.00	159.00	106.50
Annoyance	2 mA	8.92	4.35	2.50
	2 mJ	2.37	1.41	0.95
Perception	1.1 mA	4.91	2.39	1.39
	0.12 mJ	0.58	0.35	0.23

TABLE 14-8 Likely Range of Maximum Vertical Electric Field for Various Voltage Transmission Lines

Line voltage, kV	Near-ground vertical electric field, kV/m
765	8–13
500	5–9
345	4–6
230	2–3.5
161	2–3
138	2–3
115	1–2
69	1–1.5

High voltages may develop due to electric-field coupling, but the available short-circuit current is small (i.e., high-impedance source); thus calculations are based on a Norton equivalent and the short-circuit current. A relatively high resistance ground is sufficient to reduce electric-field-coupled voltage.

Table 14-8 lists maximum electric fields on the right-of-way under lines of different voltage classes. The fields attenuate rapidly with distance from the line and are usually much lower at the right-of-way edge.

Fuel Ignition. Theoretical calculations indicate that if several unlikely conditions exist simultaneously, a spark could release sufficient energy to

ignite gasoline vapors. These conditions include a perfectly grounded person refueling a car perfectly insulated from ground with a metal can while the car is parked directly under a line. The spark would have to occur in the precise location of optimum fuel-air mixture. Research^{3,28} confirms the low probability of accidental fuel ignition under actual conditions.

No confirmed cases of accidental ignition under transmission lines exist, confirming the low probability of these factors occurring simultaneously. Because of the consequences of a gasoline fire, some electric utilities advise that gasoline-fueled vehicles not be refueled near a line of 500 kV or above. If refueling were necessary, the vehicle could be grounded or the can connected to the vehicle to prevent sparks.

Ground-Level Magnetic Fields. Magnetic-field coupling affects objects which parallel the line for a distance, such as fences and pipelines, and is generally negligible for vehicle- or building-sized objects. As opposed to electric-field coupling, magnetic-field coupling is a low-voltage, low-impedance source with relatively high short-circuit currents. Single grounds are ineffective in preventing magnetically coupled voltages and multiple low-resistance grounds are needed. The resistance of the person touching a fence or pipeline is the dominant current-limiting impedance in the equivalent electrical circuit.²⁹ Calculations are based on a “longitudinal electromotive force” approach and are described in Refs. 30 to 32.

A consideration in the calculation of magnetic fields, which is different from the electric-field calculation, concerns the images. A perfectly conducting earth can be assumed for the electric-field problem, even for realistic values of earth resistivity. The assumption of a transmission line in free space (no earth at all) gives a closer approximation to the ground-level magnetic fields than does the assumption of a perfectly conducting earth for measurements near the line. At distances beyond 100 m, the effect of earth becomes increasingly more significant. The effect of conducting earth is frequently treated by use of an image conductor located at a greater depth in the earth than the conductors are above the earth. Distances of several hundred meters are commonly used for this image depth, according to the relation $D = 660 \sqrt{\rho/f}$ meters where ρ is the earth resistivity in ohm-meters and f is the frequency. Magnetic-field calculations are given in Ref. 12, including the use of Carson’s terms to evaluate the effects of imperfectly conducting earth.

It is normally adequate to consider conductors in free space without images. For the conductor of Fig. 14-8 without its image

$$B = \frac{\mu_o I}{2\pi r} = \frac{\mu_o I}{2\pi \sqrt{h^2 + L^2}} \quad (14-48)$$

This is then separated into vertical and horizontal components by multiplying by $\sin \theta$ and $\cos \theta$. In general, both components must be retained. For a 3-phase line, all conductors must be computed. Horizontal and vertical components of B from the three conductors must then be combined individually as phasors, considering the angles of the different currents. The combined horizontal and vertical

components in general have different angles, causing their resultant to trace an ellipse in time. Single-axis magnetic-field meters with the sensing coil oriented for a maximum reading give the magnitude of the major axis of the field ellipse. A three-axis meter of the type presently used for data logging responds to the square root of the sum of the squares of the three field components (the “resultant” field). The resultant field can be as much as 41% greater than the major axis of the field ellipse for circularly polarized fields of the type which result from symmetrical conductor configurations.³³

In the same manner, image currents at some assumed depth can be computed and their fields included. The use of matrix calculations allows inclusion of ground wires and bundled conductors as is the case of electric fields.

With both electric and magnetic fields it is essential to follow proper measurement procedures³³ for comparison with calculations.

For electric fields it is important that the field not be perturbed by the presence of the operator or other nearby objects. For both electric and magnetic fields, it is necessary to accurately know the conductor positions, the conductor height, the distance to the observer, and the line operating conditions (voltage and current). Magnetic-field measurements frequently differ from calculations for a number of reasons beyond errors in distance and clearance measurement:

1. Line current is continually varying, so in general it is not as well known as line voltage. In addition to uncertainty concerning the current magnitude at the time of the field measurement, line current unbalance in both magnitude and phase angle can be important. Unbalance has an increasingly significant effect on the magnetic field, the farther one moves from the line. Spot measurements, especially in homes and near distribution lines, are of limited usefulness to characterize exposure. For this reason, it is often advisable to statistically characterize the magnetic field. A statistical description of the field over time can be developed from measurements or calculations which assume balanced currents. It is also sometimes useful to develop a statistical distribution for a specific current level and an assumed maximum unbalance.
2. Related to current unbalance is circulating current in the shield wires, return currents in the earth, and currents in nearby pipes. These currents may cause significant differences between calculation and measurement.
3. The difference between single- and three-axis instruments has been described above. Two operators with different instruments can determine different answers based on the principles of measurement.
4. In nonuniform fields, such as around appliances, the size of the sensing coil and presence or absence of ferromagnetic core material will affect the reading of instruments equally well calibrated in a uniform field. Calibration must be made in a calibrating coil sufficiently large that the field is uniform over the area of the sensing coil, yet not so large that other nearby currents do not affect the field.
5. Harmonic currents have different effects depending on the frequency response of the instrument. Some instruments have a response linearly increasing with frequency, some are flat with frequency, and others have bandpass filters of different waveshapes.

14.1.6 Line Insulation

Requirements. The electrical operating performance of a transmission line depends primarily on the insulation. An insulator not only must have sufficient mechanical strength to support the greatest loads of ice and wind that may be reasonably expected, with an ample margin, but must be so designed as to withstand severe mechanical abuse, lightning, and power arcs without mechanically failing. It must prevent a flashover for practically any power-frequency operating condition and many transient voltage conditions, under any conditions of humidity, temperature, rain, or snow, and with such accumulations of dirt, salt, and other contaminants that are not periodically washed off by rains.³⁴

Insulator Materials. The majority of present insulators are made of glazed porcelain. Porcelain is a ceramic product obtained by the high-temperature vitrification of clay, finely ground feldspar, and

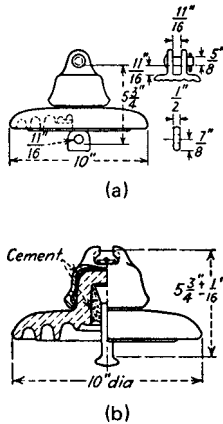


FIGURE 14-12 Typical porcelain disk insulator: (a) clevis type; (b) ball-and-socket type. (Locke Insulators Inc.)

Improvements in design and manufacture in recent years have made synthetic insulators increasingly attractive since their strength-to-weight ratio is significantly higher than that of porcelain and can result in reduced tower costs, especially on EHV and UHV transmission lines.

These insulators are usually manufactured as long-rod or post types. The light weight of most designs and resistance to damage aids construction. In addition, their performance under contaminated conditions may be significantly better than that of porcelain.³⁹

Use of synthetic insulators on transmission lines is relatively recent and a few questions are still under study, in particular the lifetime behavior of insulating shed materials under contaminated conditions. It has been found necessary to use grading rings on some types at higher voltages to prevent damage to the sheds, and a very small number of insulators have experienced "brittle fractures," in which the fiberglass core breaks close to an end fitting. Despite these problems it appears that reliable synthetic insulators are presently available.

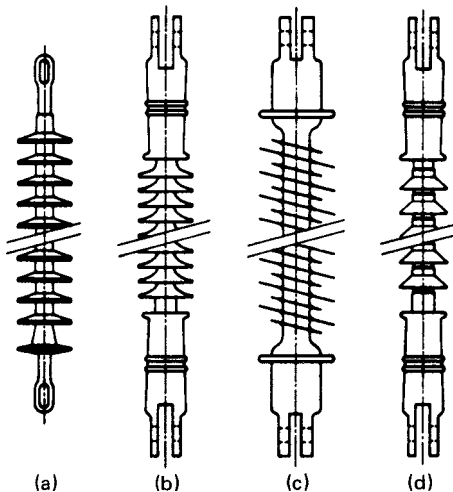


FIGURE 14-13 Typical nonceramic insulators.

silica. Insulators of high-grade electrical porcelain of the proper chemical composition free from laminations, holes, and cooling stresses have been available for many years.

The insulator glaze seals the porcelain surface and is usually dark brown, but other colors such as gray and blue are used. Porcelain insulators for transmission may be disks, posts, or long-rod types.

Porcelain insulators have been used at all transmission line voltages and, if correctly manufactured and applied, have high reliability.

A typical porcelain disk insulator is shown in Fig. 14-12.

Glass insulators have been used on a significant proportion of transmission lines. These are made from toughened glass, and are usually clear and colorless or light green. For transmission voltages they are available only as disk types. Most glass disk insulators will shatter when damaged, but without mechanically releasing the conductor. This provides a simple method of inspection.

Synthetic insulators, originally pioneered by the General Electric Company in 1963 for high-voltage transmission lines,³⁵ and more recently introduced by several manufacturers, are finding increasing acceptance. Most consist of a fiberglass rod covered by weather sheds of skirts of polymer (silicon rubber, polytetrafluoroethylene, cycloaliphatic resin, etc.)³⁶ as shown in Fig. 14-13. Other types include a cast polymer concrete called Polysil R³⁷ and a coreless type with alternating metal and insulating sections.³⁸

Insulator Design. Transmission insulators may be strings of disks (either cap and pin or ball and socket), long-rods, or line posts. Posts are only infrequently applied above 230 kV.

Present suspension insulators conform to ANSI Standard C29.2, and standards have been established for 15,000-, 25,000-, 36,000-, and 50,000-lb ratings. It is common practice to use a factor of safety of 2 for the maximum mechanical stress applied to porcelain or glass insulators. For fiberglass-core insulators it is more common for the manufacturer to supply a recommended maximum working load.

Each manufacturer supplies catalogs which provide a physical description of the insulator's mechanical characteristics, wet and dry 60-Hz flashover strength, and positive- and negative-impulse ($1.2 \times 50 \mu\text{s}$) critical (50%) flashover strength. Switching surge performance ($250 \times 3000 \mu\text{s}$)

is usually not supplied. In clean conditions most insulators of equivalent dimensions have very similar performance.

Suspension insulator strings, that is insulators used to support the conductor weight at a suspension or tangent structure, may be in I (vertical) or V configurations. The V configuration is used to prevent conductor movement and resultant clearance reductions at the structure. At dead-end or tension structures the insulators must also support the conductor tension, and it is not uncommon for these tension strings to be given a slightly higher flashover strength (e.g., by adding disks) to reduce the likelihood of a flashover that might lead to insulator string mechanical failure. Two or more strings of insulators in parallel can be used on suspension and tension strings to provide higher mechanical strength if required.

The electrical strength of line insulation may be determined by power frequency, switching surge, or lightning performance requirements. At different line voltages, different parameters tend to dominate. Table 14-9 shows typical line insulation levels and the controlling parameter. In compacted or uprated designs, considerably fewer insulators than these have been successfully used.^{40,41}

Detailed descriptions of insulation design for electrical performance for different conditions, line voltages, and line types are available⁴²⁻⁴⁴ from a number of studies.

Insulator Standards. The NEMA Publication *High Voltage Insulator Standards*, and AIEE Standard 41 have been combined in ANSI C29.1 through C29.9. Standard C29.1 covers all electrical and mechanical tests for all types of insulators. The standards for the various insulators covering flashover voltages; wet, dry, and impulse; radio influence; leakage distance; standard dimensions; and mechanical-strength characteristics are as follows: C29.2, suspension; C29.3, spool; C29.4, strain; C29.5, low- and medium-voltage pin; C29.6, high-voltage pin; C29.7, high-voltage line post; C29.8, apparatus pin; C29.9, apparatus post. These standards should be consulted when specifying or purchasing insulators.

Line Insulation Design. Power-Frequency Design. The criteria for power-frequency design is usually that flashover shall not occur for normal operating conditions, including reduced clearances to the structure from high wind. A typical wind-design limit is the 50- or 100-year return period wind, that is, a wind velocity which occurs only once in 50 or 100 years. This velocity is obtained from local wind records and may be typically 80 to 100 mi/h. Maximum operating voltages are designed by ANSI C84 and C92 standards and are 5% or 10% above the nominal value.

In clean conditions, power-frequency voltage is not a controlling parameter for insulator design (as distinct from air-gap clearance). However, even in quite lightly contaminated conditions it may become so.

Design for contamination is usually expressed as inches of creepage per kilovolt, where the creepage distance is the length of the shortest path for a current over the insulator surface and ranges up to 2 in/kV or more for heavy contamination. Standard insulator disks ($10 \times 5\frac{3}{4}$ in) have a typical creepage length of 11.5 in per disk. To avoid very long insulator strings for contamination, disks with additional creepage distance are made. The creepage can be extended by use of lengthened skirts and deeper grooves in the underside. Fog-type disks have up to 21.5 in of creepage per $13\frac{1}{2} \times 8$ -in units. A typical fog-type insulator is illustrated in Fig. 14-14.

TABLE 14-9 Typical Line Insulation

Line voltage, kV	No. of standard disks	Controlling parameter (typical)
115	7-9	Lightning or contamination
138	7-10	Lightning or contamination
230	11-12	Lightning or contamination
345	16-18	Lightning, switching surge, or contamination
500	24-26	Lightning, switching surge, or contamination
765	30-37	Switching surge or contamination

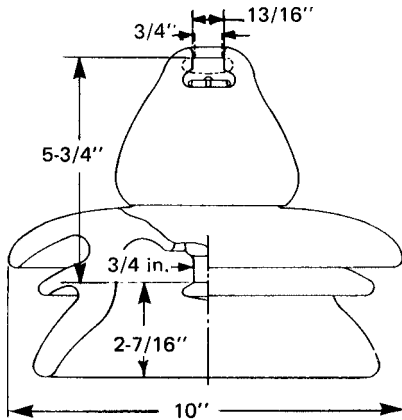


FIGURE 14-14 Typical fog-type disk insulator.

In extremely contaminated conditions, insulation with extended creepage may not be enough. In these cases insulator washing or the use of a silicone or petroleum grease coating (replaced at regular intervals) may be used.

Table 14-10 provides a simplified indication of creepage distance as a function of contamination,⁴² and Fig. 14-15 shows guidelines from the IEEE application guide.⁴³

For nonceramic insulation the same approach is used, except that subject to manufacturer's recommendations, a reduction in creepage distance up to 30% may be possible. This is due to the physical behavior of the nonceramic insulating material in moist conditions.

Another approach that has sometimes been used to combat contamination effects is the semiconductive glaze insulator. The semiconducting glaze allows a small but definite power-frequency current to flow over the surface. The insulator does not improve the standard test values, such as wet and dry power-frequency flashover

and short-time impulse flashover, although it may have some value under switching surge conditions.

The glaze has a surface resistivity of about 10 MΩ per square. This is achieved by special formulations of materials involving, at the present stage of development, the use of tin-antimony additive to a more normal glaze composition. The presence of this small leakage current, of the order of 1 to 2 mA for suspension insulators, but which can be several times that value for large porcelains (such as are used in high-voltage bushings) has three effects:

1. Linearization of the voltage distribution over the insulator or string of insulators. This aids greatly in improving the performance of the insulator with respect to corona disturbance and RIV performance, plus having some benefits under dry and clean conditions.

TABLE 14-10 Insulation Requirements for Contamination: Provisional EHV Line Insulation Design Table for Various Contamination Conditions
Standard $5^{5/34} \times 10$ -in vertical insulator units

Contamination		Equivalent amount NaCl, mg/cm ²	Provisional design values		
			Leakage distance in/kV rms line to ground	Average kV rms	
Class	Types			Per in axial length	Per unit
A	Clean atmosphere—rural and forest regions; no industrial contamination	0–0.03	Insulation requirements not set by contamination		
B	Slight atmospheric contamination; suburbs of large industrial regions; railways; frequent washing rains	0.04		1.04 2.0	11.5
C	Moderate contamination containing soluble salts up to 5%; furnaces, dust from metallurgical plants, mine dust, fly ash, fertilizer dust in small quantities	0.06		1.31 1.6	9.1
D	Severe contamination containing 15% or more of soluble salts; dust from aluminum and chemical works, cement plants, heavy agricultural fertilizing, fly ash with high salt or sulfur content	0.12		1.74 1.2	6.9
E	Salt precipitation—seaside regions, salt marshes	0.30		2.11 1.0	5.7

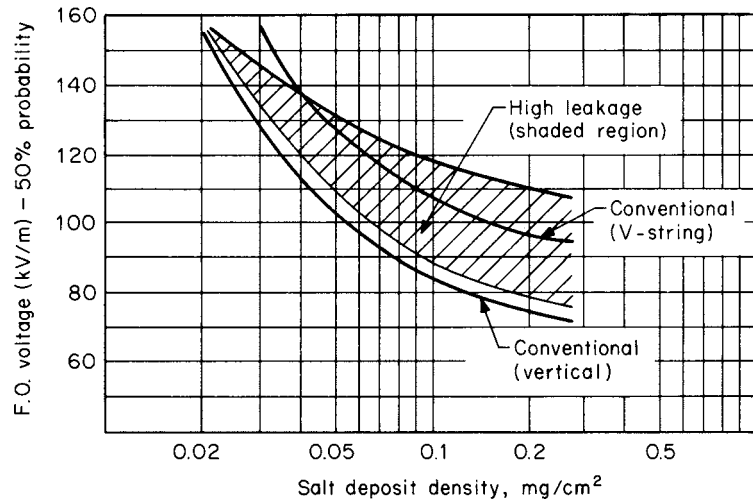


FIGURE 14-15 Power frequency withstand voltage of contaminated suspension insulators in fog expressed in kV/m of connection length (spacing).

2. Heating of the insulator. This occurs because of the power loss associated with the leakage current flow to a temperature which is usually about 5°C over the ambient air conditions. The heating effect enables the insulator to remain dry during conditions of fog or mist. This eliminates the majority of contaminated-insulator flashovers which occur when accumulated contamination becomes damp. This damp contamination condition is the most usual cause for contaminated-insulator flashover because most contaminants are more electrically conducting when damp or wet.
3. The elimination of “dry banding,” which is recognized as another major cause of flashover of standard insulators when contaminated. This occurs when the insulator has been thoroughly wetted, such as in a rain storm which wets but does not thoroughly clean the contamination from the insulator’s surface. Under these conditions dry bands will form as the standard insulator dries, and arcs strike across the dry-band area. These arcs can progress until flashover of the entire insulator occurs. With a semiconducting insulator, the relatively low resistance of the glaze shunts the dry-band area as the insulator dries and prevents the striking of the small power-frequency arcs.

The improved performance possible with semiconducting insulators has been proved in the laboratory and field,⁴⁵⁻⁴⁹ but, because of the energy losses associated with the inherent leakage current, they are not widely used.

In some severe contamination areas, the problem has been effectively attacked by the use of silicone grease coatings. The unique amoebic action of a thick layer of silicone grease on an insulating surface is such as to envelop conducting solid particles which are said to “load” up the silicone grease to the saturation point, at which time the “used” silicone grease is removed and replaced with new silicone grease. In severe contamination areas, the greasing and degreasing cycles may be required every few months; in less severe contamination areas the cycle may be a year or more depending on experience acquired. In this manner, the time between insulator cleanings can be greatly extended, thus making for substantial savings. Once the silicone coating is used, the coatings must usually be wiped off and replaced manually, as necessary. Among the manufacturers of silicone grease are the General Electric Company and the Dow-Corning Corporation.

For the cleaning operation to remove contamination from the insulator surface, many contaminants such as salt deposits and water-soluble conducting liquids can be successfully removed by

hot-line washing, using high-pressure water and insulated nozzles and hoses. Another method is “dry cleaning” by the use of an abrasive powder such as a limestone mixture or biodegradable plastic pellets, discharged at high pressure through hose and nozzle on the insulating surface. In many cases either hot-line washing or dry cleaning alone is sufficient to cope with the rate of accumulation encountered with the particular contaminant. An exception is substantially conducting materials, which take a chemical “set” after exposure to water, such as cement dust, some forms of gypsum, or asbestos, which often must first be manually chipped off or scrubbed off the insulating surface and then covered with silicone grease as previously described.

It should be emphasized that these problems may be very severe or even nonexistent, due to the variability of contamination exposure, which in turn depends on the chemical and electrical nature of the contaminant, prevailing wind direction, persistence of fog, smog, or other weather factors.

To monitor buildup of contaminants, some utilities collect data at the site to warn operating departments of an impending flashover, so as to promptly implement contamination-combative procedures.

Switching Surge Design. Operation of a circuit breaker on a transmission line can cause transient overvoltages, although flashovers due to such switching surges are rare in lines below 500 kV. If the breaker is opening, this may be due to restrikes across the breaker contacts as they separate, although restriking has been nearly eliminated with present breaker technology. If the breaker is closing, the cause may be unequal voltages on each side of the breaker, including the effect of residual charge on the line from a recent deenergization. The crest magnitudes of switching surges are normally defined in per unit of nominal power-frequency-crest phase-to-ground voltage. For example, on a 138-kV line (145 kV maximum), the per unit value is 118 kV. Typical switching surges range from 1 to as high as 4 or 5 per unit, and the varying characteristics of breaker operations provide a distribution of surge magnitudes which is often modeled as a truncated gaussian distribution.

The criterion for switching surge design is usually that flashover shall not occur for most or all switching events. Several design methods have been used, including

1. The maximum expected surge is determined, for example, from a transient network analyzer (TNA) or digital study, and the line insulation is designed to withstand that surge.
2. Rather than the maximum surge, a surge value corresponding to a statistical level is used, typically the 2% value (i.e., the crest value determined from the statistical distribution of surge crests, such that the level will be exceeded by only 2% of all surges).
3. Rather than design insulation to withstand a maximum surge, a statistical approach is used to design for a low number of flashovers per switching event. Typical levels are one flashover per 100 or 1000 breaker operations. This often results in a more economical design than either of the withstand approaches above.
4. By modeling the statistical distribution of switching surge crests, the distribution of insulator flashover with voltage, and the statistical distribution of weather that can be obtained from local weather stations, a probabilistic design can be prepared using a relatively simple computer program based on the allowable flashover rate. Typical procedures, data, and examples for such calculations are provided in several publications.^{50,51}

Impulse Surge Design. Impulse surges on a line are caused by lightning strokes to or near the line. At transmission insulation levels, only strokes that directly intercept the line are capable of causing flashovers.

A number of methods of calculating transmission-line lightning performance have been published, and are summarized in the references to Chap. 12 of Ref. 3, together with a simplified calculation method. A computer program for this simplified calculation method is available from the *IEEE WG on Transmission Line Lightning Performance*, and more sophisticated programs for evaluation of multicircuit lines are available from a number of sources.

It is unusual for line insulation to be determined by lightning performance alone. More typically, insulation is determined by other requirements and the lightning performance is then verified. If this performance is unsatisfactory, it is often more efficient to change other design parameters such as shield wires or grounding than to add insulation.

Other methods of improving lightning performance have included addition of surge arresters at relatively frequent intervals along a line, and on double-circuit lines the use of unbalanced insulation so one circuit will flash over first and protect the other. Use of line arresters is most beneficial in regions of high ground resistance. Use of unbalanced insulation can improve the performance of the circuit with the highest insulation, but at the detriment of overall line performance.

Phase-to-Phase Insulation. The controlling paths for flashovers on most presently installed transmission lines are phase-to-ground, since there are usually grounded structure components between phases. However, for some new designs, such as the Chainette,⁵² and compact lines the controlling path may be phase-to-phase air gaps or even phase-to-phase insulators.

Design methods for phase-to-phase insulation are essentially the same as for phase-to-ground insulation. Until recently, there was lack of knowledge of conductor clearance at midspan under various dynamic loading conditions, and lack of phase-to-phase switching surge data. Research studies sponsored by EPRI have now provided adequate design information on both topics.^{44,50,52}

Protective and Grading Devices. Damage to insulators from heavy arcs was a serious maintenance problem in the past, and several devices were developed to ensure that an arc would stay clear of the insulator string. Subsequent improvements in the use of overhead ground wires and fast relaying have reduced the likelihood of insulator damage to the point that arc protection devices are now rarely used in the United States.

Earlier protective measures consisted of attaching small horns to the clamp, but it was found that horns with a large spread both at the top of the insulator and at the clamp were required to be effective. Under lightning impulse the arc tends to cascade the string, and tests show that the gap between horns should be considerably less than the length of the insulator string. Protection by arcing horns thus resulted in either a reduced flashover voltage or an increase in the number of units and length of the string. In any event, flashover persisted as a power arc until the line tripped out. For these reasons arcing horns have not been used in the United States for many years, although they are fairly common in Europe.

The arcing ring or grading shield is mainly for the purpose of improving the voltage distribution over the insulator string, and its effectiveness is due to the more uniform field. Protection of the insulator is not, therefore, dependent on simply providing a shorter arcing path, as is the case with horns. Efficient rings are rather large in diameter and, for suspension strings, clearances to the structure should be at least as great as from ring to ring. These considerations have made this device generally unattractive for modern construction. Grading rings are now used only at very high voltages for special applications, or with nonceramic insulators. Corona shields help improve the voltage distribution at the line ends of insulator strings.

14.1.7 Line and Structure Location

Preparation for Construction. The cost of preparing for transmission-line construction is a considerable part of the total costs—under some conditions as much as 25%. Right-of-way and clearing are more or less fixed by local conditions, but the cost of surveys, accompanying maps, profiles, and engineering layout is to some extent governed by judgment. Many times in the past the overall costs have been increased by right-of-way difficulties and by delays in receiving proper materials because of inadequate preparations. The engineering work, properly carried out, makes it possible to obtain the right-of-way and complete the clearing well in advance of construction and to purchase every item of material and deliver it to the correct location.

The work of locating and laying out a line does not require great refinement, but careful planning is essential. With inexperienced surveyors or drafters, it must be assumed that errors will be made, and every possible device must be used to discover these errors before construction is started.

Location. The general character of the line location should be determined because it has a definite bearing on the type of design. In extreme cases, such as difficult mountainous sections or in highly developed areas near cities, this may be a determining factor in the selection of the conductor and type of structures.

On heavy trunk lines, minor repairs and replacements are not an important item, and accessibility may often be rightly sacrificed to obtain the economy of a more direct route. Light wood lines must, however, be readily accessible for inspection and repairs. Line location is a matter of judgment and requires a person of wide general experience capable of correctly weighing the divergent requirements for inexpensive and available right-of-way, low construction costs, and convenience in maintenance. In mountainous country or in thickly populated areas, it is generally not advisable to attempt a direct route or try to locate on long tangents. Small angles of a few degrees cost little more and add little to the length of line. Most designs provide suspension structures for line angles of 5° to 15° which are not excessively costly. High, exposed ridges should be avoided, to afford protection against both wind and lightning.

Following a general reconnaissance by ground and air, for which 10 to 20 days per 100 mi should be allowed, and the assembling of all available maps and information, control points can be established for a general route or areas selected for more detailed study which may prove to be determining factors in the location of the line.

With this preliminary work completed, the major difficulties should have been determined. The policy as to such matters as right-of-way condemnation, electrical environmental assessments, telephone coordination, navigable-stream crossing, air routes, airports, and crossings with other utilities must be decided as definitely as possible.

Preliminary specifications should be issued before the final survey is started. These should include (1) outline drawings of the various structures with the important dimensions; (2) conductor sag curves and a sag template; (3) the maximum spans and angles for each type of structure; and (4) the requirements for right-of-way and clearing. Estimated costs are valuable, especially comparative costs of the various types of structure. With this information the field engineer can often, in a difficult section, choose the location best suited to the design.

Aerial maps can often be secured at much less cost than preliminary surveys, and in highly developed areas may be used to advantage for completely laying out the line without sending surveyors into the area until after the right-of-way has been secured.

Photographs taken at approximately $\frac{1}{2}$ mi to the inch give sufficient detail for most work. Such maps can be photographically enlarged about four times for special detail. With a $\frac{1}{2}$ -mi-to-the-inch scale, the route of the line can be determined within a width of about 3 mi and sufficient landmarks located on a fairly accurate map to serve as a guide for flying the line.

Location Survey. The actual survey party can typically be divided into four divisions, each of which can complete at least a mile a day in average weather and country. Their operations may be carried out separately or nearly concurrently by allowing a full week's separation between successive operations and transferring personnel as needed.

The work falls naturally into the following: (1) an alignment party, choosing the exact location and cutting out the line; (2) a staking party, driving stakes at 100-ft stations and locating all obstructions; (3) a level party, taking elevations and side slopes; and (4) a property and topography party, locating property lines.

A field drafting force located at a convenient point for receiving field notes can complete the final plan and profile drawings as fast as the survey can be made.

The method of procedure and size of survey organization depend on the character of the country, the length and type of line, the experienced personnel available, and the schedule which must be maintained. In level, sparsely populated country, satisfactory but incomplete property surveys and profiles have been made during an open dry winter for a wood H-frame line 50 mi in length in approximately 4 months' time, with the personnel averaging a crew of eight and an engineer.

On a development involving the construction of several hundred miles of steel-tower line, the survey for a 65-mi line in rather difficult country, including 25 mi of inaccessible mountainous country, was completed with property maps and profiles in the form for permanent records in 2 months' time with a crew of about 20 and a locating engineer.

Purchase. Generally, right-of-way is not purchased in fee, but a perpetual easement is secured in which the owner grants the necessary rights to construct and operate the line but retains ownership and use of the land. The width of the right-of-way may be stated as a definite width or in general terms,

but the easement must provide for (1) a means of access to each structure; (2) permission to erect all structures and guys; (3) all trees and brush to be cleared over a specified width for erection; (4) the removal of trees, which would not safely clear the conductor if the conductor were to swing out under maximum wind or which would not safely clear the conductor if they were to fall; and (5) the removal of buildings, lumber piles, haystacks, etc., which constitute a fire hazard. One of the major causes of serious line outages is the neglect to adhere strictly to conservative rules for clearing.

Tower Spotting. The efficient location of structures on the profile is an important component of line design. Structures of appropriate height and strength must be located to provide adequate conductor ground clearance and minimum cost. In the past, most tower spotting has been done manually, using templates, but several computer programs have been available for a number of years for the same purpose.

Manual Tower Spotting. A celluloid template, shaped to the form of the suspended conductor, is used to scale the distance from the conductor to the ground and to adjust structure locations and heights to (1) provide proper clearance to the ground; (2) equalize spans; and (3) grade the line (Fig. 14-16).

The template is cut as a parabola on the maximum sag (usually at 49°C) of the ruling span and should be extended by computing the sag as proportional to the square of the span for spans both shorter and longer than the ruling span. By extending the template to a span of several thousand feet, clearances may be scaled on steep hillsides. The form of the template is based on the fact that, at the time when the conductor is erected, the horizontal tensions must be equal in all spans of every length, both level and inclined, if the insulators hang plumb. This is still very nearly true at the maximum temperature. The template, therefore, must be cut to a catenary or, approximately, a parabola. The parabola is accurate to within about one-half of 1% for sags up to 5% of the span, which is well within the necessary refinement.

Since vertical ground clearances are being established, the 49°C no-wind curve is used in the template. Special conditions may call for clearance checks. For example, if it is known that a line will have high temperature rise because of load current, conductor clearance should be checked for the estimated maximum conductor temperature. One crossing over a navigable stream was designed for 88°C at high water. Ice and wet snow many times cause weights several times that of the 1/2-in radial ice loading, and conductors have been known to sag to within reach of the ground. Such occurrences are not normally considered in line design, and when they occur, the line is taken out of service until the ice or snow drops. Checks made afterward have nearly always shown no permanent deformation.

The template must be used subject to a "creep" correction for aluminum conductors. Creep is a nonelastic conductor stretch which continues for the life of the line, with the rate of elongation decreasing with time. For example, the creep elongation during the first 6 months is equal to that of the next 9 1/2 years. All conductors of all materials are subject to creep, but to date only aluminum conductors have had intensive study. Creep is not substantial in other conductors, but the conductor manufacturers should be consulted. The IEEE Committee Report, "Limitations on Stringing and Sagging Conductors," in the December 1964 *Transactions of the IEEE Power Group* discusses creep, and the reader should examine that report.⁵³

Creep causes a continuous slow increase in the sag of the line which must be estimated and allowed for. The aluminum-conductor manufacturers will furnish creep-estimating curves, and most sag-tension computer programs now available are capable of calculating sags with and without creep. These curves are at approximately constant temperatures, around 15.5 to 21°C, and plot stress against elongation, one curve for each period of time, 1 h, 1 day, 1 month, 1 year, 10 years, etc. The values are integrated values for the period and are considered to be reasonable estimates. The temperature used is a reasonable average of the year's temperature across the center of the United States.

Precise values for creep are impossible to determine, since they vary with both temperature and tension, which are continuously varying during the life of the line. From Fig. 3 of the committee report in Ref. 53, it is found that a 1000-ft span of 954,000-cmil 48/7 ACSR when subjected to a constant tension of approximately 18% of its ultimate strength at a temperature of 15.5°C will have a sag increase in 1 day of approximately 5.5 in; in 10 days, 13 in; in 1 year, 27 in; in 10 years, 44 in; and in 30 years, 52 in.

Unless it is known that the line will have a life of less than 10 years, not less than 10 years' creep should be allowed for. Creep has come into consideration in transmission-line design only during the past 35 years, and to date no standards have been established for handling it. Probably the simplest approach is to check all close clearance points on the profile with a template made with no creep allowance and to specify higher structures at these points if the addition of liberal creep sag infringes on the required clearances. It is possible to prestress the creep out of small conductors, but for large conductors this requires time and special tensioning facilities not normally available. Also the time lost in constructing an EHV line will more than pay for the extra structure height required to compensate for the creep. Prestressing changes the modulus of elasticity, and this new modulus should be used in the design.

The vertical weight supported at any structure is the weight of the length of conductor between low points of the sag in the two adjacent spans. For bare-conductor weights, this distance between low points can be scaled by using a template of the sag at any desired temperature. The maximum weight under loaded conditions should be scaled from a template made for the loaded sags. For most problems, the horizontal distance may be taken as equal to the conductor length. Distances to the low point of the sag may be computed by Eq. (14-65).

Uplift. On steep inclined spans the low point may fall beyond the lower support; this indicates that the conductor in the uphill span exerts a negative or upward pull on the lower tower. The amount of this upward pull is equal to the weight of the conductor from the lower tower to the low point in the sag. Should the upward pull of the uphill span be greater than the downward load of the next adjacent span, actual uplift would be caused, and the conductor would tend to swing clear of the tower.

It is important that abrupt changes in elevation of the structures should not occur, so that the conductor will not tend to swing clear of any structure even at low temperatures. This condition would be indicated if the 0°F curve of the template can be adjusted to hang free of the center support and just touch the adjacent supports on either side. In northern states it would be well to add a curve to the template for the below-zero temperatures experienced.

Insulator Swing. The uplift condition should not even be approached in laying out suspension insulator construction; that is, each tower should carry a considerable weight of conductor. The minimum weight that should be allowed on any structure may be logically determined by finding the transverse angle to which the insulator string may swing without reducing the clearance from the conductor to the structure too greatly. Also, the ratio of vertical weight to horizontal wind load should be limited to avoid insulator swing beyond this angle. The maximum wind is usually assumed at a temperature of 60°F. The wind pressure, measured in pounds per square foot, to be used in swing calculations is a matter of judgment and depends on local conditions. Under high-wind conditions it is reasonable to require somewhat less than normal clearances. Generally a clearance corresponding to about 75% of the flashover value of the insulator is adequate. The insulator will swing in the direction of the resultant of the vertical and horizontal forces acting on the insulator string as shown in Fig. 14-16.

Long Spans. Rough country may necessitate spans considerably longer than contemplated in the design and may involve a number of factors including (1) proper clearance between conductors, (2) excessive tensions under maximum load, and (3) structures adequate to carry the additional loads.

Safe horizontal clearance between conductors is often based on the National Electrical Safety Code (NESC) formula, in which the spacing a in inches is given as proportional to the square root of sag; s is in inches.

$$a = 0.3 \text{ in/kV} + 8 \sqrt{\frac{s}{12}} \quad (14-49)$$

This relation was developed for, and is useful on, comparatively short span lines of the smaller conductors and for voltages up to 69 kV; but for very long spans and heavy conductors, the formula results in spacings considerably larger than have proved satisfactory. It also results in spacings that are questionably small for very light conductors on long spans. Percy H. Thomas proposed an empirical formula which takes into account the weight of the conductor and its diameter, requiring less spacing for heavy conductors and a greater spacing for small conductors by the ratio of diameter D in inches to weight w in pounds per foot (D/w) as a means of determining the required conductor

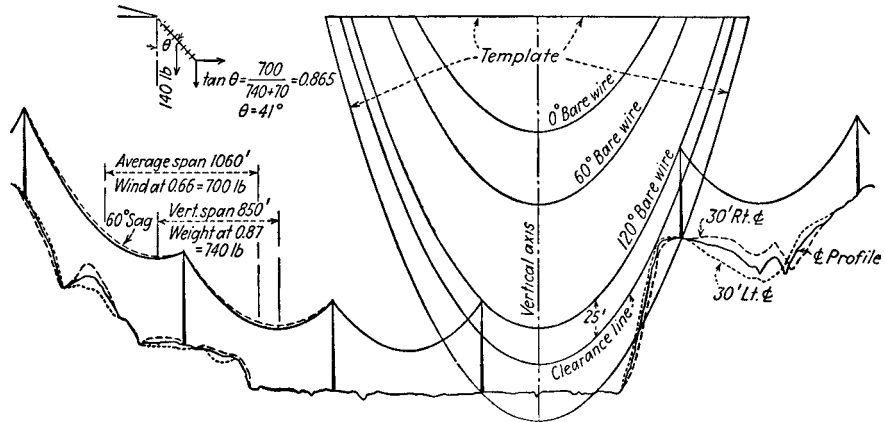


FIGURE 14-16 Sag template determines clearances of a suspended conductor from the ground.

spacing for the average span of the line. The factor C in Eq. (14-81) includes an allowance to permit the standard spacing to be used on somewhat longer spans than average construction. The same formula, however, may be used to examine the spacings which have been successfully used on maximum spans and a value for C selected from experience for determining the safe spacing required for an occasional unusually long span.

Excessive tensions on very long spans may be avoided by dead-ending at both ends and computing such a stringing sag as will result in the same maximum tension as elsewhere in the line. Such a span will be found to have considerably greater stringing sag and lower stringing tension than the normal span. Sag curves or charts are often prepared giving the sag for dead-end spans of various lengths such that the maximum tension under loaded conditions will be the same.

Dead-end construction is costly, and consideration should be given to avoiding this additional expense. It is common practice to permit spans up to double the average span without dead ends, although spans of this length may require additional spacing between wires. A careful examination of some trial figures on the sags and tensions developed in a long span will often indicate how great a span may be carried on suspension structures. The maximum loaded tension which would occur in a long span, if this span were dead-ended and sagged to the same stringing tension as the rest of the line, compared with the maximum tension for normal span lengths, is a good indication of the necessity for dead-end construction.

In case a number of long spans are encountered in a line or section of line, it may prove more economical to reduce the tension in the entire section to the long-span values and accept an increase in sag and corresponding reduction in span length in order to avoid dead ends.

Computerized Tower Spotting.⁵⁴⁻⁵⁶ In a line of any significant length there are a very large number of possible tower location sequences which meet the requirement for minimum electrical clearances yet also meet the maximum load limits of the chosen structure family. With considerable design experience, it is possible to select a reasonably economical tower spotting solution, but no manual tower spotting method can explore all the possibilities nor find the lowest-cost solution.

In recent years, computer programs have become available to explore nearly all possible tower spotting solutions, selecting those having the lowest cost. In addition to exploring minimum-cost tower spotting solutions for new lines, these computer programs also allow the user to explore uprating alternatives including reconductoring, adding structures, raising attachment points, and retensioning the existing conductors. With the advent of more and more powerful personal computers and easier-to-use graphical interfaces, these programs can be applied even to relatively small line designs. Such programs are particularly attractive when modern digital methods of obtaining terrain data or existing line structure locations, heights, and catenaries can be used to collect the vast amount of input data required.

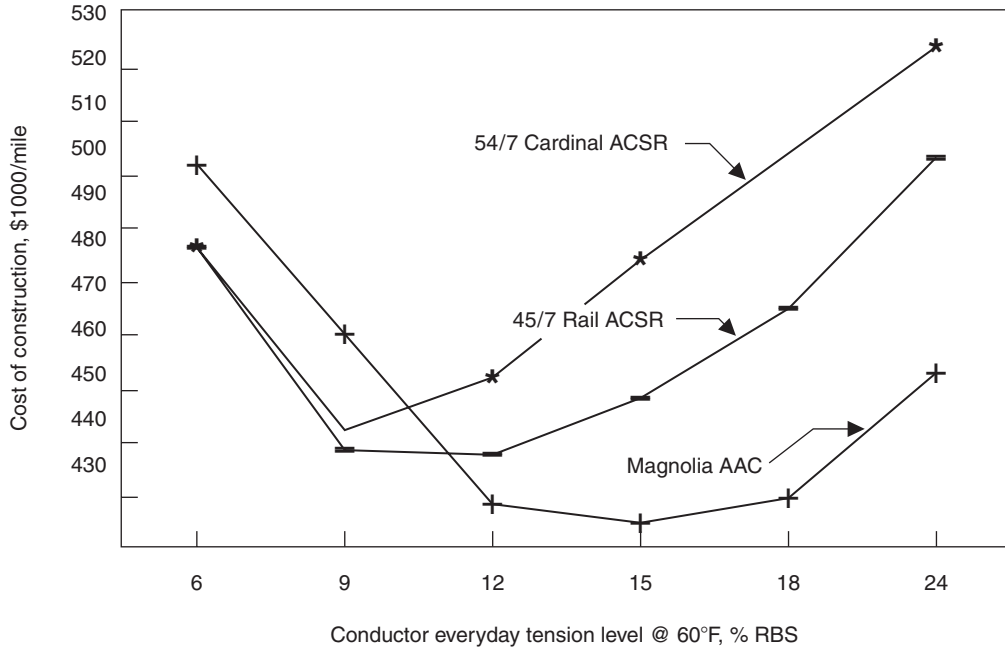


FIGURE 14-17 Cost of construction versus conductor tensions for 1200-ft (366 m) wind span.

Digital data collection and analysis allows the line designer to explore a number of design aspects that were simply impossible just a short time ago. For example, Fig. 14-17 shows the result of a series of lowest-cost numerical tower spotting calculations made to explore the effects of conductor type (all-aluminum conductor, low-steel 45/7 ACSR, and high-steel 54/7 ACSR) and conductor stringing tension expressed as a percent of rated breaking strength (RBS). Each data point represents a optimized tower spotting calculation. It's interesting to note that the lowest-cost solution is the weakest conductor at a modest tension level.

14.1.8 Mechanical Design of Overhead Spans

Conductor and Structure Loads. The span design consists of determining the sag at which the conductor shall be erected so that heavy winds, accumulations of ice or snow, and low temperatures, even if sustained for several days, will not stress the conductor beyond the elastic limit, cause a serious permanent stretch, or result in fatigue failures from continued vibrations.

Unit wind and ice loadings for conductors are found by the following formulas:

$$\text{Wind load (lb/ft)} = p \times \left(\frac{D}{12} \right) \quad (14-50)$$

$$\text{Ice load (lb/ft)} = 1.244 \times (Dr + r^2) \quad (14-51)$$

where p is the wind pressure in pounds per square foot, D is the diameter of the conductor in inches, and r is the radial thickness of the ice in inches. The ice is assumed to be glaze ice with a unit weight of 57 lb/ft³.

The dead weight of the conductor and the weight of the accumulated ice act vertically; the wind load is assumed to act horizontally and at right angles to the span; the resultant is the vectorial sum.

Under combined vertical and horizontal loading, the conductor swings out into an inclined plane whose angle with the vertical is the angle between the direction of the vertical force and the resultant force. The resulting deflection is measured in this inclined plane.

The following procedures for calculating extreme loadings on transmission line conductors and structures are based on a reliability-based design (RBD) methodology described in ASCE Manual 74.⁵⁷ These represent the minimum loading levels for which transmission lines in the United States should be designed. For critical or important lines, more stringent requirements than those given below should be specified to provide improved reliability of the lines. Detailed procedures for designing for higher levels of line reliability are given in Manual 74.

Extreme Wind Loading. The wind pressure p at height z above ground level, in pounds per square foot, is given by the following formula:⁵⁷

$$p = 0.00256(Z_v V)^2 G C_f \quad (14-52)$$

where V = the basic wind speed, in miles per hour, determined from the wind-speed contour map in Fig. 14-18

C_f = the force coefficient given in Table 14-11 or 14-12

Z_v = the terrain factor given in Table 14-13

G = the gust response factor given in Fig. 14-19a through d

The exposure categories required for the determination of p_z are defined in Table 14-14. These exposure categories and the basic wind-speed map in Fig. 14-18 are not applicable to sections of transmission lines that cross high mountain ridges, large river valleys, or other topographic features where localized wind speed-up effects may occur. In these cases, special meteorological studies should be conducted to establish the appropriate wind loadings.

The basic wind-speed contour map in Fig. 14-18 is taken from ASCE Standard 7-88.⁵⁸ Wind speeds from this map represent the 50-year return period fastest-mile speeds at 33 ft above ground for exposure category C.

The effective height z for determining the terrain factor and gust response factor is the distance above ground level to the center of pressure of the conductor or structure. For conductors, it can be approximated as the average height above ground of the conductor attachment points to the structure minus one-third the sum of the insulator length (for suspension insulators only) and the sag of the conductors. For support structures with total heights of 200 ft or less, the effective height can be approximated as two-thirds the total height of the structure. For structures taller than 200 ft, the terrain factor should be varied over the height of the structure to represent the increase in the wind speed with height above ground.

Extreme Ice Loading. The radial ice thickness r for the extreme ice loading condition can be determined from the ice map in Fig. 14-20.⁵⁷ This map gives estimates of the average 50-year return period glaze ice thicknesses for five regions of the United States. Since this map was developed from limited observations of icing on overhead lines, it should be used only if statistical data on extreme ice loadings for the region of the transmission line are not available.

Combined Ice and Wind Loading. For combined ice and wind loading conditions, the glaze ice thickness determined from Fig. 14-20 should be combined with a wind speed equal to 0.4 times the wind speed from the wind contour map in Fig. 14-18. The basis for this reduced wind speed is described in ASCE Manual 74.⁵⁷ In cases where statistical data on wind speeds during icing conditions are available, those data should be used in lieu of this wind-speed reduction.

Wire Tensions. The wire tensions for the extreme wind loading case should be based on the temperature that is most likely to occur at the time of the extreme wind events. For example, it could be the average of the minimum daily temperatures

TABLE 14-11 Force Coefficients for Cylindrical Surfaces

Description of surface	C_f
Stranded cables (conductors, ground wires, guy wires)	1.0
Smooth circular cylinder	0.9
Rough circular cylinder	1.2
16-sided polygon	0.9
12-sided polygon	1.0
Octagon	1.4

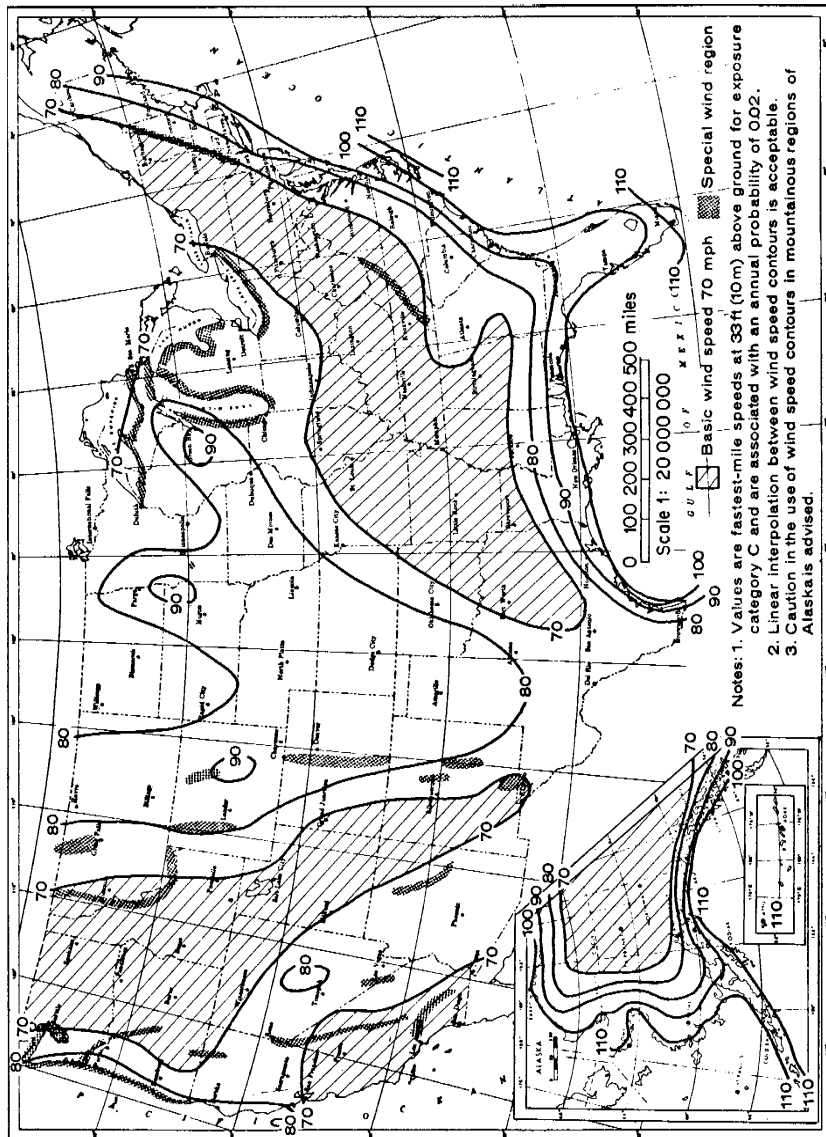


FIGURE 14-18 Basic wind speed, mi/h.

TABLE 14-12 Force Coefficients for Lattice Towers, C_f

ϵ	C_f	
	Square towers	Triangular towers
<0.025	4.0	3.6
$0.025-0.44$	$4.1-5.2\epsilon$	$3.7-4.5\epsilon$
$0.45-0.69$	1.8	1.7
$0.7-1.0$	$1.3 + 0.7\epsilon$	$1.0 + \epsilon$

Notes: ϵ is the ratio of solid area to gross area of tower face.

Force coefficients are given for towers with structural angles or similar flat-sided members.

For towers with rounded members, the design wind force shall be determined using the values in this table multiplied by the following factors:

$\epsilon \leq 0.29$	factor = 0.67
$0.3 \leq \epsilon \leq 0.79$	factor = $0.67\epsilon + 0.47$
$0.8 \leq \epsilon \leq 1.0$	factor = 1.0

For triangular-section towers, the design wind forces shall be assumed to act normal to a tower face.

For square-section towers, the design wind forces shall be assumed to act normal to a tower face. To allow for the maximum horizontal wind load, which occurs when the wind is oblique to the faces, the wind load acting normal to a tower face shall be multiplied by the factor $1.0 + 0.75\epsilon$ for $\epsilon < 0.5$ and shall be assumed to act along a diagonal.

for the strong-wind season. A wire temperature of 15°F is recommended for computing the wire tensions for the combined ice and wind loading case. Although ice accretion typically occurs at temperatures somewhat greater than this, the 15°F temperature accounts for a possible cold front passing after the icing event.

Catenary Calculations for Stranded Conductors. The energized conductors of transmission and distribution lines must be placed in a manner that totally eliminates the possibility of injury to people. Overhead conductors, however, elongate with time, temperature, and tension, thereby changing their original positions after installation. Despite the effects of weather and loading on a line, the conductors must remain at safe distances from buildings, objects, and people or vehicles passing

TABLE 14-13 Terrain Factor, Z_v

Height above ground level, z ft	Z_v		
	Exposure B	Exposure C	Exposure D
0-33	0.72	1.00	1.18
40	0.75	1.03	1.21
50	0.78	1.06	1.23
60	0.82	1.09	1.26
70	0.85	1.11	1.28
80	0.88	1.14	1.29
90	0.91	1.16	1.31
100	0.93	1.17	1.32
120	0.96	1.20	1.35
140	0.99	1.23	1.37
160	1.02	1.26	1.39
180	1.05	1.28	1.40
200	1.08	1.30	1.42

Notes: Linear interpolation for intermediate values of height z is acceptable. Exposure categories are defined in Table 14-1.

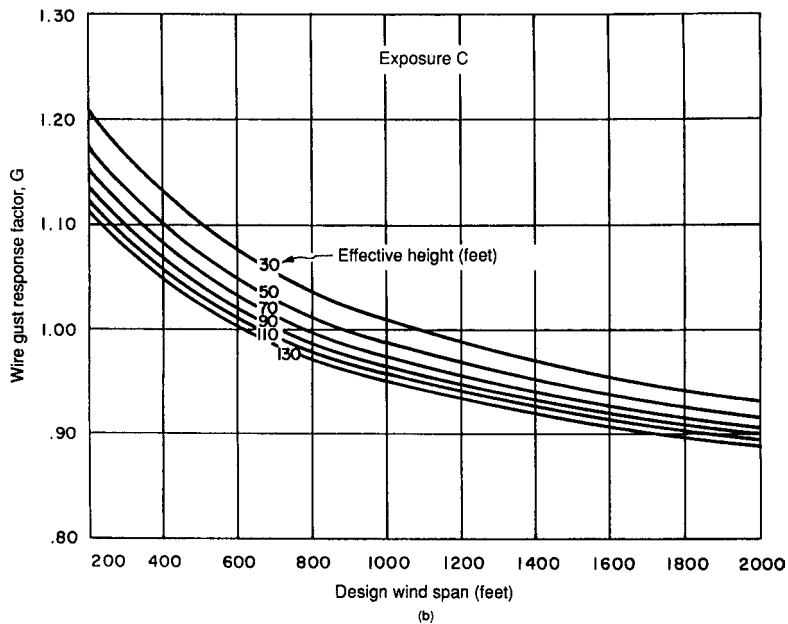
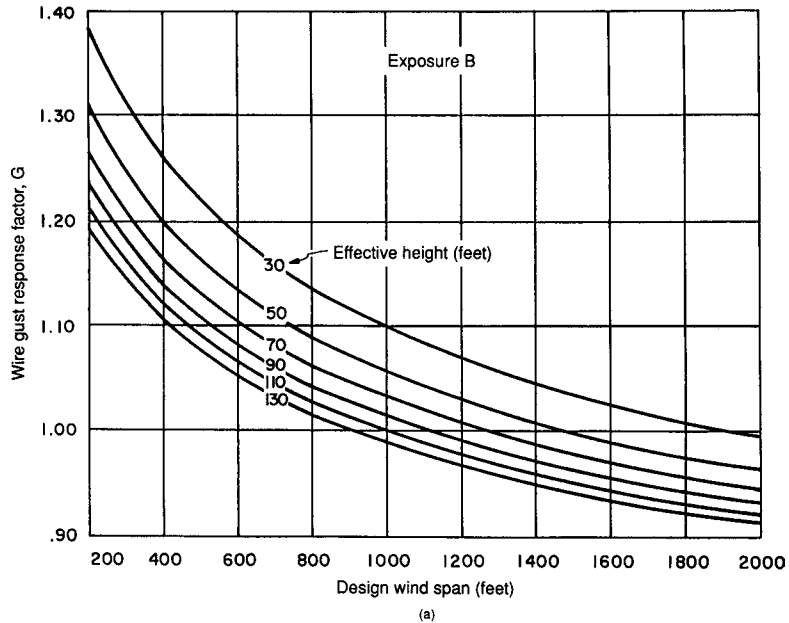


FIGURE 14-19 Conductor gust response factor, exposures B (a), C (b), and D (c); structure gust response factor (d).

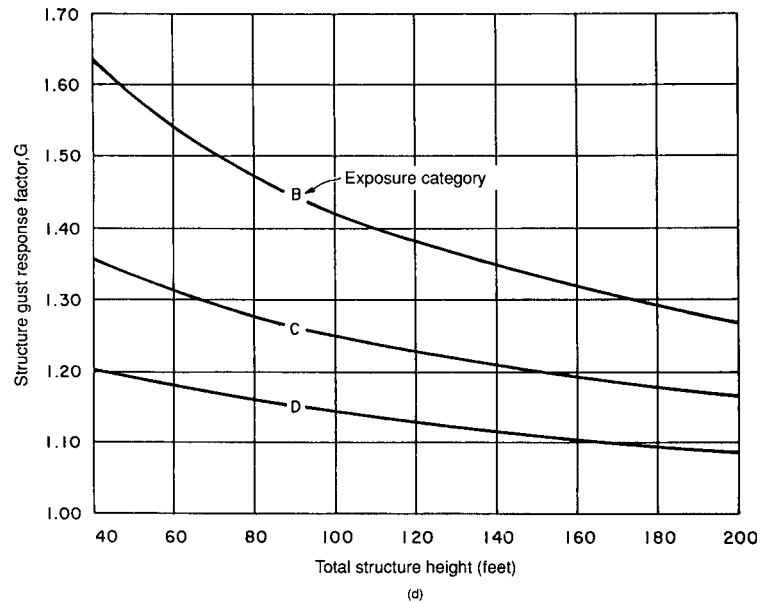
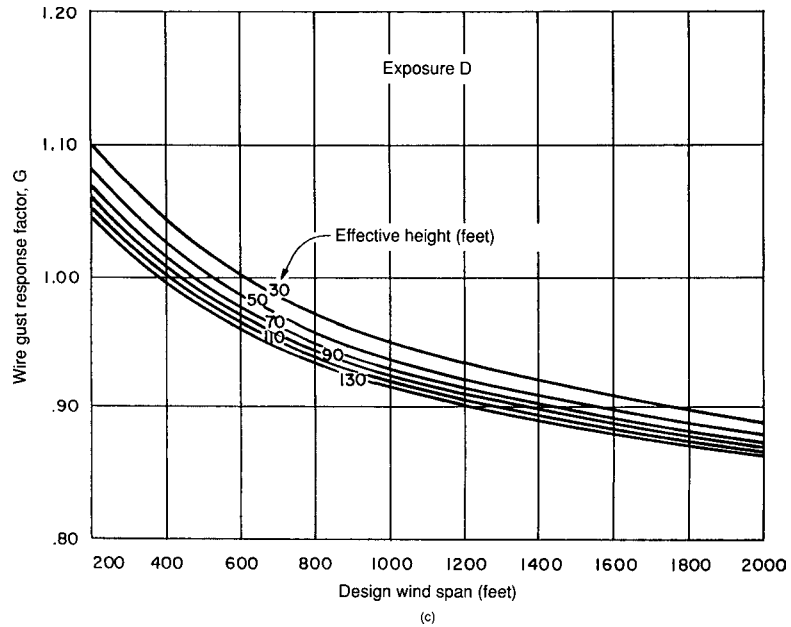


FIGURE 14-19 (Continued)

TABLE 14-14 Description of Exposure Categories

Exposure category	Description
B	Suburban areas, wooded areas, or other terrain with numerous closely spaced obstructions having the size of single-family dwellings or larger
C	Open terrain with scattered obstructions having heights generally less than 30 ft, e.g., cultivated fields and grasslands
D	Flat, unobstructed coastal areas directly exposed to wind flowing over large bodies of water

beneath the line at all times. To ensure this safety, the shape of the terrain along the right-of-way, the height and lateral position of the conductor between support points, and the position of the conductor between support points under all wind, ice, and temperature conditions must be known.

Bare overhead transmission or distribution conductors are typically flexible and uniform in weight along their lengths. Because of these characteristics, they take the form of a catenary between support points. The shape of the catenary^{59,60} changes with conductor temperature, ice and wind loading, and time. To ensure adequate vertical and horizontal clearance under all weather and electrical loadings, and to ensure that the breaking strength of the conductor is not exceeded, the behavior of the conductor catenary under all conditions must be incorporated into the line design. The required prediction of the future behavior of the conductor are determined through calculations commonly referred to as *sag-tension calculations*, which predict the behavior of conductors according to recommended tension limits under varying loading conditions. These tension limits specify certain percentages of the conductor's rated breaking strength that is not to be exceeded on installation or during the life of the line. These conditions, along with the elastic and permanent elongation properties of the conductor, provide the basis for determining the amount of resulting sag during installation and long-term operation of the line.

Accurately determined initial sag limits are essential in the line design process. Final sags and tensions depend on initial installed sags and tensions and on proper handling during installation. The final sag shape of conductors is used to select support point heights and span lengths so that the minimum clearances will be maintained over the life of the line. If the conductor is damaged or the initial sags are incorrect, the line clearances may be violated or the conductor may break during heavy ice or wind loadings.

Sag and Tension in Level Spans. A bare stranded overhead conductor is normally held clear of objects, people, and other conductors by periodic attachment to insulators. The elevation differences between the supporting structures affect the shape of the conductor catenary. The catenary's shape has a distinct effect on the sag and tension of the conductor, which can be determined using well-defined mathematical equations.

The shape of a catenary is a function of the conductor weight per unit length w , the horizontal component of tension, H , the span length S , and the sag of the conductor D . Conductor sag and span length are illustrated in Fig. 14-21 for a level span.

The exact catenary equation uses hyperbolic functions. Relative to the low point of the catenary curve shown in Fig. 14-21, the height of the conductor $y(x)$ above this low point is given by the following equation:

$$y(x) = \frac{H}{w} \left[\cosh \left(\frac{wx}{H} \right) - 1 \right] \cong \frac{wx^2}{2H} \quad (14-53)$$

Note that x is positive in either direction from the low point of the catenary. The expression to the right is an approximate parabolic equation based on a MacLaurin series expansion of the hyperbolic cosine.

For a level span, the low point is in the center and the sag D is found by substituting $x = S/2$ in the preceding equations. The exact catenary and approximate parabolic equations for sag become the following:

$$D = \frac{H}{w} \left[\cosh \left(\frac{wS}{2H} \right) - 1 \right] \cong \frac{wS^2}{8H} \quad (14-54)$$

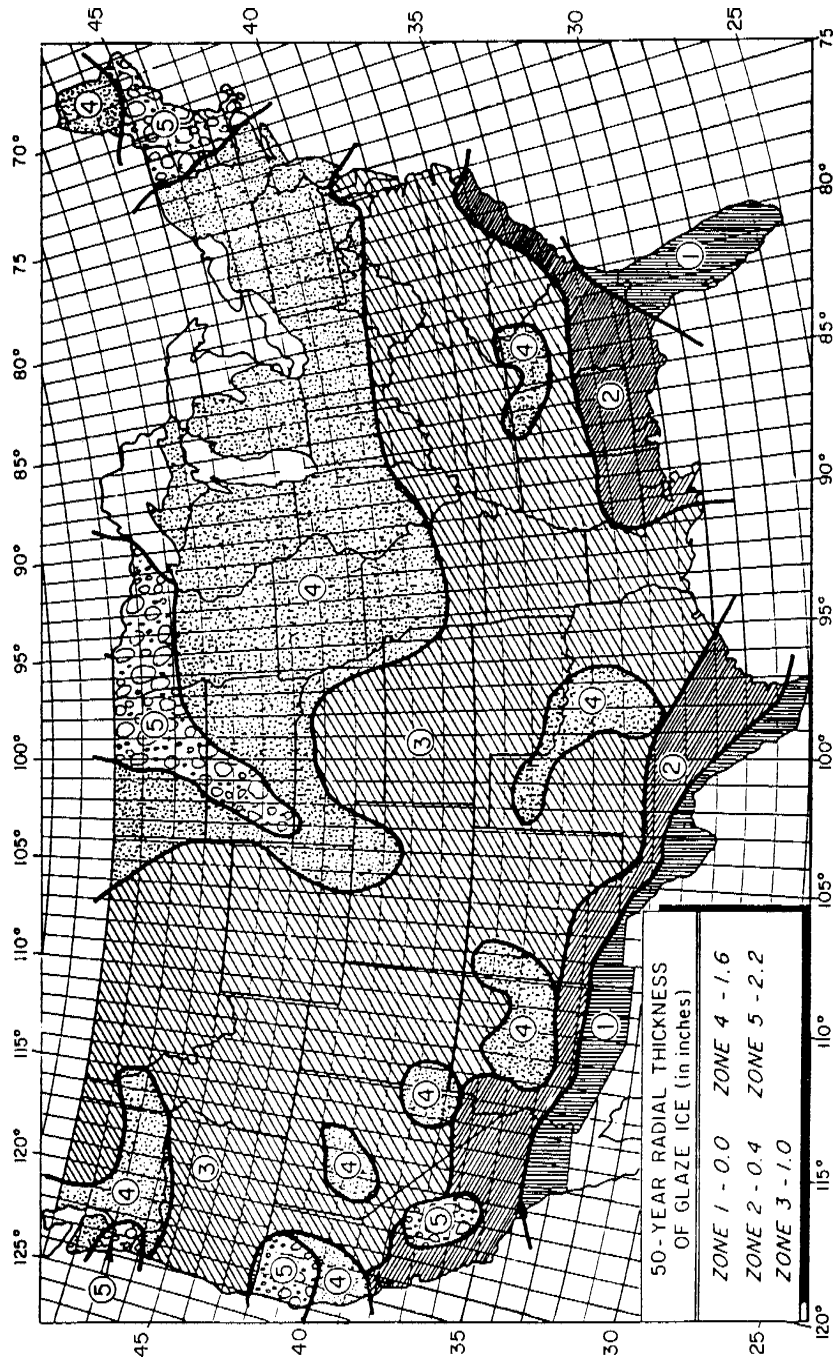


FIGURE 14-20 Extreme radial thickness of glaze ice having a 50-year return period.

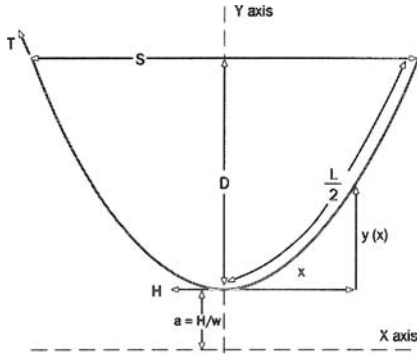


FIGURE 14-21 The catenary curve for level spans.

The ratio H/w which appears in all of the preceding equations is commonly referred to as the *catenary constant*. An increase in the catenary constant causes the catenary curve to become shallower and the sag to decrease. Although it varies with conductor temperature, ice and wind loading, and time, the catenary constant typically has a value in the range of several thousand feet for most transmission-line catenaries.

The approximate, or parabolic, expression is sufficiently accurate as long as the sag is less than 5% of the span length. As an example, consider a 1000-ft (304.5-m) span of Drake ACSR conductor with a per unit weight of 1.096 lb/ft (15.99 N/m) installed at a tension of 4500 lb (20.016 kN). The catenary constant H/w is 4106 ft (1251.8 m). The calculated sag is 30.48 ft (9.293 m) and 30.44 ft (9.280 m) using the hyperbolic and approximate parabolic equations, respectively. For this case where the sag-to-span ratio is 3.4%, the difference in calculated sag between the hyperbolic and parabolic equations is 0.48 in (1.3 cm).

The horizontal component of tension H is equal to the conductor tension at the point in the catenary where the conductor slope is horizontal. For a level span, this is the midpoint of the span. At the ends of the level span, the conductor tension T is equal to the horizontal component plus the conductor weight per unit length w multiplied by the sag D , as shown in the following:

$$T = H + wD \quad (14-55)$$

Given the conditions in the preceding example calculation for a 1000-ft (304.8-m) level span of ACSR Drake, the tension at the attachment points T exceeds the 4500-lb (20.016-N) horizontal component of tension H by only 36 lb (162 N), a difference of only 0.8%.

This shows that the use of horizontal tension H and parabolic equations for the catenary are adequate for typical transmission spans and sags. However, there is little reason to use either approximation in numerical methods.

Conductor Length. Application of calculus to the catenary equation allows the calculation of the conductor length $L(x)$ measured along the conductor from the low point of the catenary in either direction.

The equation for catenary length between the supports is

$$L(x) = \frac{H}{w} \sinh \left(\frac{wx}{H} \right) \cong x \left(1 + \frac{x^2 w^2}{6H^2} \right) \quad (14-56)$$

For a level span, the conductor length corresponding to $x = S/2$, is half of the total conductor length L ; thus

$$L = \left(\frac{2H}{w} \right) \sinh \left(\frac{Sw}{2H} \right) \cong S \left(1 + \frac{S^2 w^2}{24H^2} \right) \quad (14-57)$$

The parabolic equation for conductor length can also be expressed as a function of sag D by substitution of the sag parabolic equation [Eq. (14-54)]:

$$L = S + \frac{8D^2}{3S} \quad (14-58)$$

Conductor slack is the difference between the conductor length L and the span length S . The parabolic equations for slack may be found by equating and rearranging the preceding parabolic equations for conductor length L and sag D :

$$L - S \cong S^3 \left(\frac{w^2}{24H^2} \right) \cong D^2 \left(\frac{8}{3S} \right) \quad (14-59)$$

While slack has units of length, it may also be expressed as a percentage of the span length. In the preceding catenary calculation, the length of the catenary is 1002.471 ft (305.63 m) and the slack is 2.471 ft (0.753 m), which is 2.47% of the span length. According to the ruling-span approximation, which is discussed later, the tension H and the tension to weight per unit length ratio H/w is the same in all suspension spans between strain structures. Therefore the slack in each suspension span is proportional to the cube of the suspension span length and the total slack is determined largely by the longest spans. It is for this reason that the ruling span is closer to the longest span rather than the average span.

Equation (14-58) can be inverted to obtain an equation showing the dependence of sag D on slack $L - S$:

$$D = \sqrt{\frac{3S(L - S)}{8}} \quad (14-60)$$

Given the preceding 1000-ft (304.5-m) level span of Drake ACSR conductor with 2.471 ft (0.753 m) of slack, a reduction of 6 in (15.2 cm) in slack yields a sag reduction of 3.25 ft (0.99 m). As can be seen from the preceding, small changes in slack typically yield large changes in conductor sag and tension, particularly for short spans.

Sag and tension in inclined spans may be analyzed using essentially the same equations that were used for level spans. The catenary equation for the conductor height above the low point in the span is the same. However, the span is considered to consist of two separate sections, one to the right of the low point and the other to the left as shown in Fig. 14-22. The shape of the catenary relative to the low point is unaffected by the difference in suspension point elevation (span inclination). In each direction from the low point, the conductor elevation $y(x)$ relative to the low point is given by Eq. (14-53):

$$y(x) = \frac{H}{w} \left[\cosh \left(\frac{wx}{H} \right) - 1 \right] = \frac{wx^2}{2H}$$

Note that x is considered positive in either direction from the low point.

The horizontal distance x_L from the left support point to the low point in the catenary is

$$x_L = \frac{S}{2} \left(1 + \frac{h}{4D} \right) \quad (14-61)$$

The horizontal distance x_R from the right support point to the low point of the catenary is

$$x_R = \frac{S}{2} \left(1 - \frac{h}{4D} \right) \quad (14-62)$$

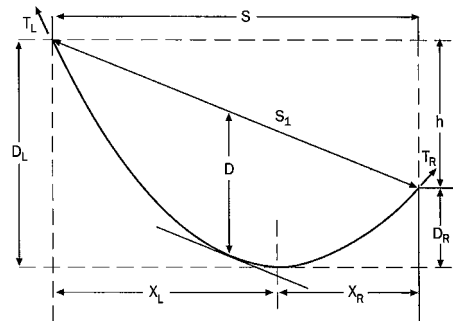


FIGURE 14-22 Inclined catenary span.

where S = horizontal distance between support points

h = vertical distance between support points

S_1 = straight-line distance between support points

D = sag measured vertically from a line through the points of conductor support to a line tangent to the conductor

(as shown in Fig. 14-22). The midpoint sag D is approximately equal to the sag in a horizontal span, with a length equal to the inclined span S_1 .

Knowing the horizontal distance from the low point to the support point in each direction, we can apply the preceding equations for $y(x)$, L , D , and T to each side of the inclined span. The total conductor length L in the inclined span is equal to the sum of the lengths in the x_R and x_L subspan sections:

$$L = S + (x_L^3 + x_R^3) \left(\frac{w^2}{6H^2} \right) \quad (14-63)$$

In each subspan, the sag is relative to the corresponding support point elevation

$$D_R = \frac{Wx_R^2}{2H}, \quad D_L = \frac{Wx_L^2}{2H} \quad (14-64)$$

or in terms of sag D and the vertical distance between support points

$$D_R = D \left(1 - \frac{h}{4D} \right)^2, \quad D_L = D \left(1 + \frac{h}{4D} \right)^2 \quad (14-65)$$

and the maximum tension is

$$T_R = H + wD_R, \quad T_L = H + wD_L \quad (14-66)$$

or in terms of upper and lower support points:

$$T_u = T_1 + wh \quad (14-67)$$

where D_R = sag in right subspan section

D_L = sag in left subspan section

T_R = tension in right subspan section

T_L = tension in left subspan section

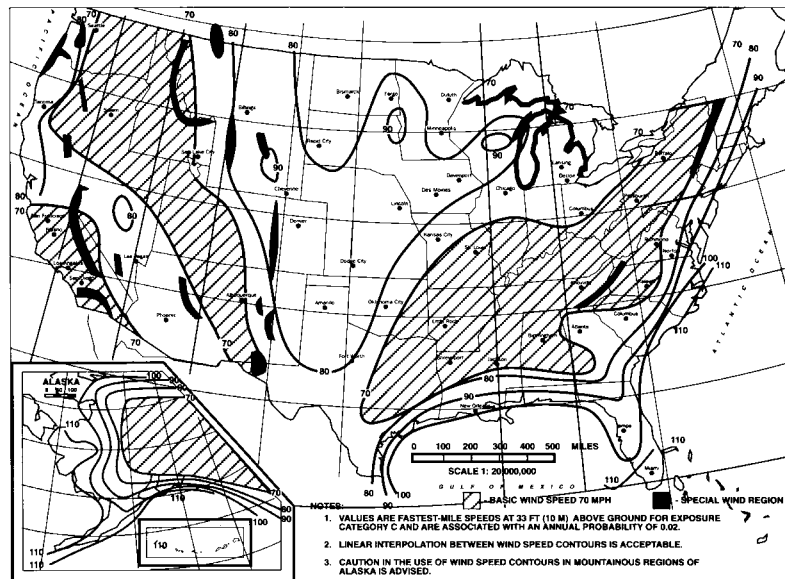
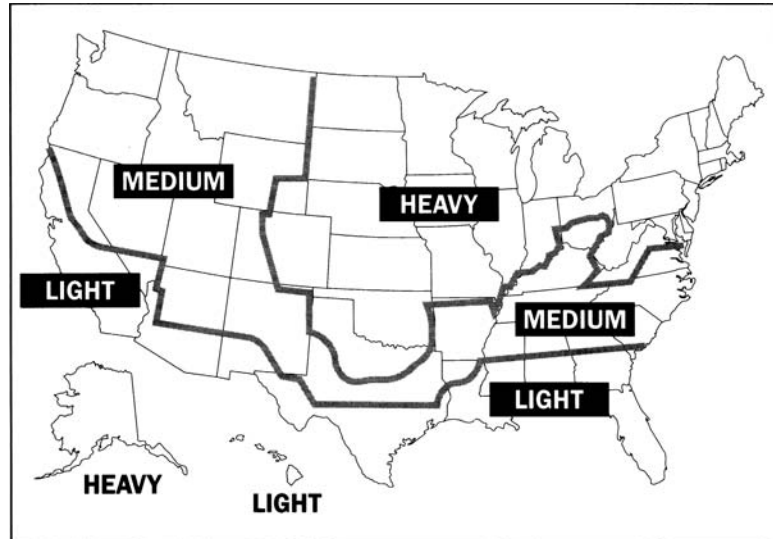
T_u = tension in conductor at upper support

T_1 = tension in conductor at lower support

The horizontal conductor tension is equal at both supports. The vertical component of conductor tension is greater at the upper support, and the resultant tension, T_u , is also greater.

Ice and Wind Conductor Loads. When a conductor is covered with ice and/or is exposed to wind, the effective conductor weight per unit length increases. During occasions of heavy ice and/or wind load, the conductor catenary tension increases dramatically along with the loads on angle and dead-end structures. Both the conductor and its supports can fail unless these high-tension conditions are considered in the line design.

The *National Electrical Safety Code* (NESC) suggests certain combinations of ice and wind corresponding to heavy, medium, and light loading regions of the United States. Figure 14-23a is a map of the United States indicating those areas. The combinations of ice and wind corresponding to loading region are listed in Table 14-15. The NESC also suggests that increased conductor loads due to high wind loads without ice be considered. Figure 14-23b shows the suggested wind pressure as a function of geographic area for the U.S. (NESC).



This figure is reproduced by permission of the American Society of Civil Engineers. [10]

FIGURE 14-23 (a) Ice and wind load areas of the United States. (b) Wind-pressure design values for the United States. (American Society of Civil Engineers).

Certain utilities in very heavy ice areas use glaze ice thickness of as much as 2 in (50 mm) to calculate iced conductor weight. Similarly, utilities in regions where hurricane winds occur may use wind loads as high as 34 lb/ft² (1620 Pa). As the NESC indicates, the degree of ice and wind loads varies by region. Some areas may have heavy icing, whereas some areas may have extremely high winds. The loads must be accounted for in the line design process to prevent a detrimental effect on

TABLE 14-15 Ice and Wind Loading For NESC Loading Districts

	Loading districts			Extreme wind loading
	Heavy	Medium	Light	
Radial thickness of ice, in (mm)	0.5 (12.5)	0.25 (6.25)	0	0
Horizontal wind pressure, lb/ft ² (Pa)	4 (190)	4 (190)	9 (430)	see Fig. 2-4 (NESC)
Temperature, °F (°C)	0 (−20)	+15 (−10)	+30 (−1)	+60 (+15)
Constant to be added to the resultant (all conductors), lb/ft (N/m)	0.30 (4.40)	0.20 (2.50)	0.05 (0.70)	0.0 (0.0)

the line. Some of the effects of both the individual and combined components of ice and wind loads are discussed below:

Ice loading of overhead conductors may take several physical forms (glaze ice, rime ice, or wet snow). The impact of lower-density ice formation is usually considered in the design of line sections at high altitudes.

The formation of ice on overhead conductors has the following influence on line design:

- Ice loads determine the maximum vertical conductor loads that structures and foundations must withstand.
- In combination with simultaneous wind loads, ice loads also determine the maximum transverse loads on structures.
- In regions of heavy ice loads, the maximum sags and the permanent increase in sag with time (difference between initial and final sags) may be due to ice loadings.

Ice loads for use in designing lines are normally derived on the basis of past experience, code requirements, state regulations, and analysis of historical weather data. Mean recurrence intervals for heavy ice loadings are a function of local conditions along various routings. The impact of varying assumptions concerning ice loading can be investigated with line design software.

The calculation of ice loads on conductors is normally done with an assumed glaze ice density of 57 lb/ft³ (8950 N/m³). The weight of ice per unit length is calculated with the following equation:

$$w_{\text{ice}} = 0.0281t(D_c + t) \quad (14-68)$$

where t = radial thickness of ice, mm

D_c = conductor outside diameter, mm

w_{ice} = resultant weight of ice, N/m

The ratio of iced weight to bare weight depends strongly on conductor diameter. As shown in Table 14-16, for three different conductors covered with 0.5-in radial glaze ice, this ratio ranges from 4.8 for No. 1/0 AWG wire to 1.6 for 1590-kcmil conductors. As a result, small-diameter conductors may need to have a higher elastic modulus and higher tensile strength than do large conductors in heavy ice and wind loading areas to limit sag.

TABLE 14-16 Ratio of Iced to Bare Conductor Weight

ACSR Conductor	D_c , in	W_{bare} , lb/ft	W_{ice} , lb/ft	$\frac{W_{\text{bare}} + W_{\text{ice}}}{W_{\text{bare}}}$
No. 1/0 AWG 6/1 "Raven"	0.398	0.1452	0.559	4.8
477-kcmil 26/7 "Hawk"	0.858	0.6570	0.845	2.3
1590-kcmil 54/19 "Falcon"	1.545	2.044	1.272	1.6

Conductor wind loading influences line design in a number of ways:

- The maximum span between structures may be determined by the need for horizontal clearance to edge of right-of-way during moderate winds.
- The maximum transverse loads for tangent and small-angle suspension structures are often determined by infrequent high-wind-speed loadings.
- Permanent increase in conductor sag may be determined by wind loading in areas of light ice load.

Wind-pressure load on conductors P_w is commonly specified in pounds per square foot (lb/ft²). The relationship between P_w and wind velocity is given by the following equation:

$$P_w = 0.00256(V_w)^2 \quad (14-69)$$

where V_w is the wind speed in miles per hour.

The wind load per unit length of conductor W_w is equal to the wind-pressure load P_w multiplied by the conductor diameter (including radial ice of thickness t , if any):

$$W_w = P_w \frac{(D_c + 2t)}{12} \quad (14-70)$$

Combined Ice and Wind Loading. If the conductor weight is to include both ice and wind loading, the resultant magnitude of the loads must be determined. The weight of a conductor under both ice and wind loading is given by the following equation:

$$w_{w+i} = \sqrt{(w_b + w_i)^2 + (W_w)^2} \quad (14-71)$$

where w_b = bare conductor weight per unit length, lb/ft (N/m)

w_i = weight of ice per unit length, lb/ft (N/m)

w_w = wind load per unit length, lb/ft (N/m)

w_{w+i} = resultant of ice and wind loads, lb/ft (N/m)

The NESC prescribes a safety factor K in pounds per foot, dependent on loading district, to be added to the resultant ice and wind loading when performing sag and tension calculations. Therefore, the total resultant conductor weight w is

$$w = w_{w+i} + K \quad (14-72)$$

Conductor Tension Limits. The NESC recommends limits on the tension of bare overhead conductor as a percentage of the conductor's rated breaking strength. The tension limits are 60% under maximum ice and wind loading, 35% initial unloaded (when installed) at 60°F, and 25% final unloaded (after maximum loading has occurred), also at 60°F. It is common, however, for lower unloaded tension limits to be used. Except in areas experiencing severe ice loading, it is not unusual to find tension limits of 60% maximum, 25% unloaded initial, and 15% unloaded final. This set of specifications could easily result in an actual maximum tension on the order of only 35% to 40%, an initial tension of 20%, and a final unloaded tension level of 15%. In this case, the 15% tension limit is said to govern.

Transmission-line conductors are seldom covered with ice, and winds on the conductor are usually much lower than those used in maximum load calculations. Under such everyday conditions, tension limits are specified to limit eolian vibration to safe levels. Even with everyday lower tension levels of 15% to 20%, it is assumed that vibration control devices will be used in those sections of the line which are subject to severe vibration. Eolian vibration levels, and thus appropriate unloaded tension limits, vary with the type of conductor, the terrain, the span length, and the use of dampers. Special conductors such as ACSS, SDC, and VR, which exhibit high self-damping properties, may be installed to the full code limits, if desired.

Recent studies by CIGRE Working Group B2/11 led to the development of a guide for choosing suitable installed conductor tension levels. The recommendations are in the form of maximum allowable ratios of tension (H in pounds or Newtons) to weight per unit length (w in lb/ft or N/m). The primary determinants of the maximum H/w ratio include the type of conductor (e.g., ACSR or AAC). The type of terrain (e.g., 4 terrain types, #1 being open, flat, not trees, no obstructions, etc.), and a span parameter LD/m where L is the span length, D is the conductor diameter, and m is the mass per unit length of the conductor.

Approximate Sag-Tension Calculations. Sag-tension calculations, using detailed experimental stress-strain and creep elongation laboratory data, are usually performed with the aid of a computer; however, with certain simplifications, these calculations can be made with a handheld calculator. The latter approach allows greater insight into the calculation of sags and tensions than is possible with complex computer programs. Equations suitable for such calculations, as presented in the preceding section, can be applied to the following example:

It is desired to calculate the sag and slack for a 600-ft level span of 795 kcmil-26/7 ACSR Drake conductor. The bare conductor weight per unit length w_b is 1.094 lb/ft. The conductor is installed with a horizontal tension component H of 6300 lb, equal to 20% of its rated breaking strength of 31,500 lb. The sag for this level span is

$$D = \frac{1.094(600)^2}{(8)6300} = 7.81 \text{ ft (2.38 m)}$$

The length of the conductor between the support points is determined from

$$L = 600 + \frac{8(7.81)^2}{3(600)} = 600.27 \text{ ft (182.96 m)}$$

Note that the conductor length depends solely and directly on span and sag. It is not directly dependent on conductor tension, weight, or temperature. The *conductor slack* is the conductor length minus the span length; in this example, it is 0.27 ft (0.082 m).

Sag Change with Thermal Elongation. The ACSR and AAC conductors elongate with increasing conductor temperature. The rate of linear thermal expansion for the composite ACSR conductor is less than that of the AAC conductor because the steel strands in the ACSR elongate at approximately half the rate of aluminum. The composite coefficient of linear thermal expansion of a nonhomogenous conductor, such as ACSR Drake, may be found from the following equations:⁶¹

$$\alpha_{AS} = \alpha_{Al} \left(\frac{F_{Al}}{E_{AS}} \right) \left(\frac{A_{Al}}{A_{total}} \right) + \alpha_{St} \left(\frac{E_{St}}{E_{AS}} \right) \left(\frac{A_{St}}{A_{total}} \right) \quad (14-73)$$

$$E_{AS} = E_{Al} \left(\frac{A_{Al}}{A_{total}} \right) + E_{St} \left(\frac{A_{St}}{A_{total}} \right) \quad (14-74)$$

where E_{Al} = modulus of elasticity of aluminum, lb/in²
 E_{St} = modulus of elasticity of steel, lb/in²
 E_{AS} = modulus of elasticity of aluminum-steel composite, lb/in²
 A_{Al} = area of aluminum strands, square units
 A_{St} = area of steel strands, square units
 A_{total} = total cross-sectional area, square units
 α_{Al} = aluminum coefficient of linear thermal expansion, °F⁻¹
 α_{St} = steel coefficient of thermal elongation, °F⁻¹
 α_{AS} = composite aluminum-steel coefficient of thermal elongation, °F⁻¹

Of course, the modulus of elasticity of an ACSR conductor is not linear. Its elongation is a complex function of both the present stress and prior stress loading over time. Nonetheless, it is informative

to calculate the thermal elongation for approximate elasticity moduli for steel and aluminum strands.

Using elastic moduli of 8 and 28 million lb/in² for aluminum and steel, respectively, the elastic modulus for ACSR Drake is

$$E_{AS} = (8.6 \times 10^6) \left(\frac{0.6247}{0.7264} \right) + (27 \times 10^6) \left(\frac{0.1017}{0.7264} \right) = 11.2 \times 10^6 \text{ lb/in}^2$$

and the coefficient of linear thermal expansion is

$$\begin{aligned} \alpha_{AS} &= 12.8 \times 10^{-6} \left(\frac{8.6 \times 10^6}{11.2 \times 10^6} \right) \left(\frac{0.6247}{0.7264} \right) + 6.4 \times 10^{-6} \left(\frac{27 \times 10^6}{11.2 \times 10^6} \right) \left(\frac{0.1017}{0.7264} \right) \\ &= 10.6 \times 10^{-6} \text{ } ^\circ\text{F}^{-1} \end{aligned}$$

If the conductor temperature changes from a reference temperature T_{ref} to another temperature T , the conductor length L changes in proportion to the product of the conductor's effective coefficient of linear thermal elongation α_{AS} and the change in temperature $T - T_{\text{ref}}$ as follows:

$$L_T = L_{T_{\text{ref}}} [1 + \alpha_{AS}(T - T_{\text{ref}})] \quad (14-75)$$

For example, if the temperature of the Drake conductor in the preceding example increases from 60°F (15°C) to 167°F (75°C), then the length increases by 0.68 ft (0.21 m) from 600.27 ft (182.96 m) to 600.95 ft (183.17 m):

$$L(\text{at } 167^\circ\text{F}) = 600.27[1 + (10.6 \times 10^{-6})(167 - 60)] = 600.95 \text{ ft}$$

Ignoring for the moment any change in length due to change in tension, the sag at 167°F (75°C) may be calculated for the conductor length of 600.95 ft (183.17 m) using Eq. (14-60):

$$D = \sqrt{\frac{3(600)(0.95)}{8}} = 14.6 \text{ ft (4.45 m)}$$

Using a rearrangement of Eq. (14-54), this increased sag is found to correspond to a decreased tension of

$$H = \frac{w(S^2)}{8D} = \frac{1.094(600)^2}{8(14.6)} = 3372 \text{ lb (15,100 N)}$$

If the conductor were inextensible, that is, if it had an infinite modulus of elasticity, then these values of sag and tension for a conductor temperature of 167°F would be correct. For any real conductor, however, the elastic modulus of the conductor is finite and changes in tension change the conductor length. Use of the preceding calculation, therefore, will overstate the increase in sag.

Sag Change Due to Combined Thermal and Elastic Effects. With moduli of elasticity around the 10-million-lb/in² level, typical bare aluminum and ACSR conductors elongate about 0.01% for every 1000-lb/in² change in tension. In the preceding example, the increase in temperature caused an increase in length and sag and a decrease in tension, but the effect of tension change on length was ignored. As discussed later, concentric-lay stranded conductors, particularly nonhomogenous conductors such as ACSR, are not inextensible. Rather, they exhibit quite complex elastic and plastic behavior. Initial loading of conductors results in elongation behavior substantially different from that caused by loading many years later. Also, high-tension levels caused by heavy ice and wind loads cause a permanent increase in conductor length, affecting subsequent elongation under various conditions.

Accounting for such complex stress-strain behavior usually requires a sophisticated, computer-aided approach. For illustration purposes, however, the effect of permanent elongation

of the conductor on sag and tension calculations will be ignored, and a simplified elastic conductor assumed. This idealized conductor is assumed to elongate linearly with load and to undergo no permanent increase in length, regardless of loading or temperature. For such a conductor, the relationship between tension and length is

$$L_H = L_{H,\text{ref}} \left[1 + \frac{H - H_{\text{ref}}}{E_c A} \right] \quad (14-76)$$

where L_H = length of conductor under horizontal tension, H
 $L_{H,\text{ref}}$ = length of conductor under horizontal reference tension, H_{ref}
 E_c = modulus of elasticity of the conductor, lb/in²
 A = cross-sectional area, in²

In calculating sag and tension for extensible conductors, it is useful to add a step to the preceding calculation of sag and tension for elevated temperature. This added step allows a separation of thermal elongation and elastic elongation effects, and involves the calculation of a zero-tension length (ZTL) at the conductor temperature of interest T_{cdr} . This ZTL (T_{cdr}) is the conductor length attained if the conductor is taken down from its supports and laid on the ground with no tension. By reducing the initial tension in the conductor to zero, the elastic elongation is also reduced to zero, shortening the conductor. It is even possible that for short spans, the zero tension length can be less than the span length.

Consider the preceding example for ACSR Drake in a 600-ft level span. The initial conductor temperature is 60°F, the conductor length is 600.27 ft, and E_{AS} is calculated to be 11.2×10^6 lb/in². Using Eq. (14-76), the reduction of the initial tension from 6300 lb to zero yields a ZTL at 60°F of

$$\text{ZTL}_{(60^\circ\text{F})} = 600.27 \left[1 + \frac{0 - 6300}{(11.2 \times 10^6)(0.7264)} \right] = 599.80 \text{ ft (182.82 m)}$$

Keeping the tension zero and increasing the conductor temperature to 167°F yields a purely thermal elongation. The zero tension length at 167°F can be calculated using Eq. (14-75):

$$\text{ZTL}_{(167^\circ\text{F})} = 599.80 \text{ ft } [1 + (10.6 \times 10^{-6})(167 - 60)] = 600.48 \text{ ft}$$

According to Eqs. (14-54) and (14-60), this length corresponds to a sag of 10.2 ft and a horizontal tension of 4412 lb. However, this length was calculated for zero tension; it will elongate elastically under tension. The actual conductor sag-tension determination requires a process of iteration as follows:

1. As described above, the conductor's ZTL, calculated at 167°F (75°C), is 600.48 ft; sag is 10.2 ft; and the horizontal tension H is 4412 lb.
2. Because the conductor is elastic, the tension of 4412 lb will increase the conductor length from 600.48 ft to

$$L_{1(167^\circ\text{F})} = 600.48 \left[1 + \frac{4412 - 0}{(0.7264)(11.2 \times 10^6)} \right] = 600.80 \text{ ft (183.12 m)}$$

3. The sag $D_1(167^\circ\text{F})$ corresponding to this length is calculated using Eq. (14-60):

$$D_{1(167^\circ\text{F})} = \sqrt{\frac{3(600)(0.80)}{8}} = 13.4 \text{ ft (4.09 m)}$$

4. Using Eq. (14-54), this sag yields a new horizontal tension $H_1(167^\circ\text{F})$ of

$$H_1 = \frac{1.094(600)^2}{8(13.4)} = 3674 \text{ lb}$$

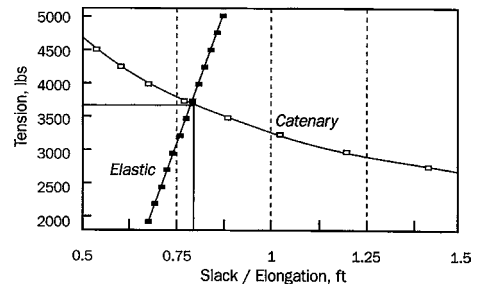
TABLE 14-17 Iterative Solution for Increased Conductor Temperature

Iteration no.	Length L_n , ft	Sag D_n , ft	Tension H_n , lb	New trial tension, lb
ZTL	600.48	10.2	4412	—
1	600.80	13.4	3674	$\frac{4412 + 3674}{2} = 4043$
2	600.77	13.2	3730	$\frac{3730 + 4043}{2} = 3887$
3	600.76	13.1	3758	$\frac{3758 + 3887}{2} = 3823$
4	600.75	13.0	3787	$\frac{3787 + 3823}{2} = 3805$

A new trial tension is taken as the average of H and H_1 , and the process is repeated. The results are described in Table 14-17.

Note that the balance of thermal and elastic elongation of the conductor yields an equilibrium tension of approximately 3800 lb and a sag of 13.0 ft. The calculations of the previous section, which ignored elastic effects, result in lower tension (3372 lb) and a greater sag (14.6 ft).

Slack is equal to the excess of conductor length over span length. Table 14-17 can be replaced by a plot of the catenary and elastic curves on a graph of slack versus tension. The solution occurs at the intersection of the two curves. Figure 14-24 shows the tension-versus-slack curves intersecting at a tension of 3800 lb, which agrees with the preceding calculations.

**FIGURE 14-24** Sag-tension solution for 600-ft (183-m)

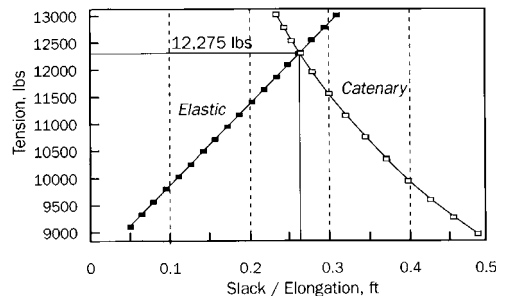
Sag Change Due to Ice Loading. As a final example of sag-tension calculation, calculate the sag and tension for the 600-ft span of Drake with the addition of 0.5 in of radial ice and a drop in a conductor temperature to 0°F. The weight of the conductor increases by

$$\begin{aligned}
 w_{ice} &= 1.244t(D_c + t) = 1.244(0.5)(1.108 + 0.5) \\
 &= 1.000 \text{ lb/ft (14.6 N/m)}
 \end{aligned}$$

As in the previous example, the calculation uses the conductor's ZTL at 60°F, which is the same as that found in the previous section, 599.80 ft. The ice loading is specified for a conductor temperature of 0°F, so the ZTL at 0°F, using Eq. (14-75), is

$$\begin{aligned}
 \text{ZTL}_{(0^\circ\text{F})} &= 599.80[1 + (10.6 \times 10^{-6})(0 - 60)] \\
 &= 599.42 \text{ ft}
 \end{aligned}$$

As in the case of sag and tension at elevated temperatures, the conductor tension is a function of slack and elastic elongation. The conductor tension and the conductor length are found at the point of intersection of the catenary and elastic curves (Fig. 14-25). The intersection of the curves occurs at a horizontal tension component of 12,275 lb, not

**FIGURE 14-25** Sag-tension solution for 600-ft (183-m) span of Drake ACSR at 0°F (−17.8°C) and 0.5-in ice.

very far from the crude initial estimate of 12,050 lb, that ignored elastic effects. The sag corresponding to this tension and the iced conductor weight per unit length is 9.2 ft.

In spite of doubling the conductor weight per unit length by adding 0.5 in of ice, the sag of the conductor is much less than the sag at 167°F. This condition is generally true for transmission conductors where minimum ground clearance is determined by the high temperature rather than the heavy loading condition. Small distribution conductors, such as the 1/0–AWG ACSR in Table 14-16, experience a much larger ice-to-conductor weight ratio (4:8), and the conductor sag under maximum wind and ice load may exceed the sag at moderately higher temperatures.

The preceding approximate tension calculations could have been more accurate with the use of actual stress-strain curves and graphic sag-tension solutions, as described in detail in Ref. 62. This method, although accurate, is very slow and has been replaced completely by computational methods.⁶³

Experimental Stress-Strain Curves. Sag-tension calculations are normally done numerically and allow the user to enter many different loading and conductor temperature conditions. Both initial and final conditions are calculated, and multiple tension constraints can be specified. The complex stress-strain behavior of ACSR-type conductors can be modeled numerically, including both temperature and elastic and plastic effects.

Stress-strain curves for bare overhead conductors include a minimum of an initial curve and a final curve over a range of elongations from 0% to 0.45%. For conductors consisting of two materials, an initial and final curve for each is included. Creep curves for various lengths of time are typically included as well.

Overhead conductors are not purely elastic. They stretch with tension, but when the tension is reduced to zero, they do not return to their initial length. Thus, conductors are plastic; the change in conductor length cannot be expressed with a simple linear equation, as used in the preceding hand calculations. The permanent length increase that occurs in overhead conductors yields the difference in initial and final sag-tension data found in most computer programs.

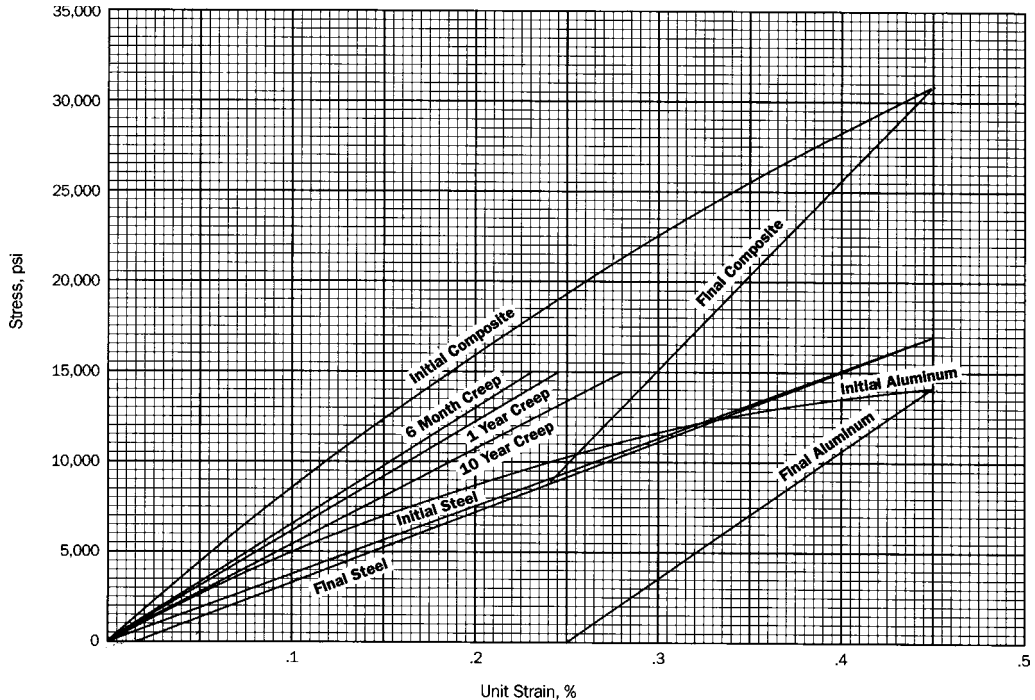
Figure 14-26 shows a typical stress-strain curve⁶⁴ for a 26/7 ACSR conductor; the curve is valid for conductor sizes ranging from 266.8 to 795 kcmil. A 795-kcmil 26/7 ACSR Drake conductor has a breaking strength of 31,500 lb (14,000 kg) and an area of 0.7264 in² (46.9 mm²) so that it fails at an average stress of 43,000 lb/in² (30 kg/mm²). The stress-strain curve illustrates that at a stress equal to 50% of the conductor's breaking strength (21,500 lb/in²), the elongation is less than 0.3%. This translates to an elongation of 1.8 ft (0.55 m) in a 600-ft (180-m) span.

Note that the component curves for the steel core and the aluminum-stranded outer layers are separated. This separation allows for changes in the relative curve locations as the temperature of the conductor changes.

For the preceding example, with the Drake conductor at a tension of 6300 lb (2860 kg), the length of the conductor in the 600-ft (180-m) span was found to be 0.27 ft longer than the span. This tension corresponds to a stress of 8600 lb/in² (6.05 kg/mm²). From the stress-strain curve in Fig. 14-26, this corresponds to an initial elongation of 0.105% (0.63 ft). As in the preceding hand calculation, if the conductor tension is zero, its unstressed length would be less than the span length.

Figure 14-27 is a stress-strain curve⁶⁴ for an all-aluminum 37-strand conductor ranging in size from 250 to 1033.5 kcmil. Because the conductor is made entirely of aluminum, there is only one initial curve and one final curve.

Permanent Conductor Elongation Due to High Tensions. Once a conductor has been installed to an initial tension, it can elongate further. Such elongation results from two phenomena: permanent elongation due to high-tension levels resulting from ice and wind loads and creep elongation under everyday tension levels. These types of conductor elongation are discussed in the following sections. Both Figs. 14-26 and 14-27 indicate that when the conductor is initially installed, it elongates nonlinearly. If the conductor tension increases to a relatively high level under ice and wind loading, the conductor will elongate. When the wind and ice loads abate, the conductor elongation will reduce along a curve parallel to the final curve, but will never return to its original length.



Equations for Curves (X = unit strain in %; Y = stress in psi):

$$\begin{aligned} \text{Initial Composite: } & X = 4.07 \times 10^{-3} + (1.28 \times 10^{-5}) Y - (1.18 \times 10^{-10}) Y^2 + (5.64 \times 10^{-15}) Y^3 \\ & Y = -512 + (8.617 \times 10^4) X - (1.18 \times 10^4) X^2 - (5.76 \times 10^4) X^3 \end{aligned}$$

$$\text{Initial Steel: } Y = (37.15 \times 10^3) X$$

$$\text{Initial Aluminum: } Y = -512 + (4.902 \times 10^4) X - (1.18 \times 10^4) X^2 - (5.76 \times 10^4) X^3$$

$$\text{Final Composite: } Y = (107.55 X - 17.65) \times 10^3$$

$$\text{Final Steel: } Y = (38.60 X - 0.65) \times 10^3$$

$$\text{Final Aluminum: } Y = (68.95 X - 17.00) \times 10^3$$

$$\text{6 Month Creep: } Y = (64.75 \times 10^3) X$$

$$\text{1 Year Creep: } Y = (60.60 \times 10^3) X$$

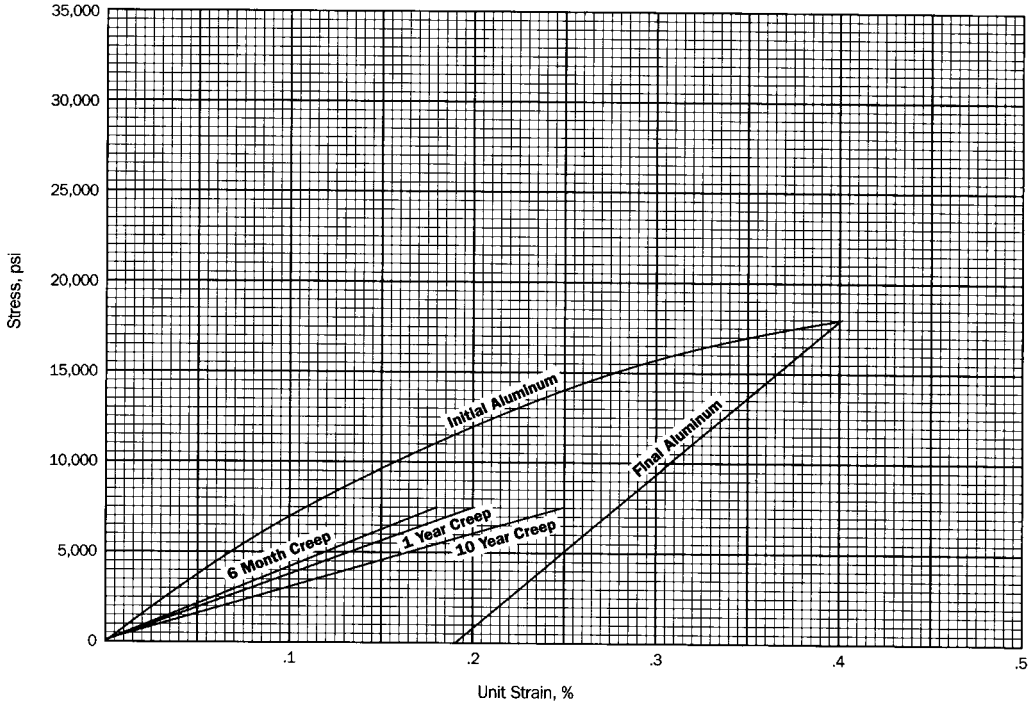
$$\text{10 Year Creep: } Y = (53.45 \times 10^3) X$$

Test Temperature 70°F to 75°F

FIGURE 14-26 Stress-strain curves for 26/7-strand ACSR.

For example, refer to Fig. 14-27 and assume that a newly strung 795-kcmil, 37-strand Arbutus AAC has an everyday tension of 2780 lb. The conductor area is 0.6245 in², so the everyday stress is 4450 lb/in² and the elongation is 0.062%. Following an extremely heavy ice and wind load event, assume that the conductor stress reaches 18000 lb/in². When the conductor tension decreases back to everyday levels, the conductor elongation will be permanently increased by more than 0.2%. Also the sag under everyday conditions will be correspondingly greater, and the tension will be less. In most numerical sag-tension methods, final sag-tension values are calculated for such permanent elongation due to heavy loading conditions.

Permanent Elongation at Everyday Tensions (Creep). Conductors permanently elongate under tension even if the tension level never exceeds everyday levels. This permanent elongation caused by everyday tension levels is called *creep*.⁶⁴ Creep can be determined by long-term laboratory creep tests.



Equations for Curves (X = unit strain in %; Y = stress in psi):

$$\text{Initial Aluminum: } Y = -5.31 \times 10^{-3} + (1.74 \times 10^{-5})X - (6.17 \times 10^{-10})X^2 + (5.05 \times 10^{-14})X^3$$

$$Y = 136 + (7.46 \times 10^4)X - (8.51 \times 10^4)X^2 + (2.33 \times 10^4)X^3$$

$$\text{Final Aluminum: } Y = (85.20X - 16.14) \times 10^3$$

$$\text{6 Month Creep: } Y = (42.30 \times 10^3)X$$

$$\text{1 Year Creep: } Y = (38.20 \times 10^3)X$$

$$\text{10 Year Creep: } Y = (30.60 \times 10^3)X$$

Test Temperature 70°F to 75°F

FIGURE 14-27 Stress-strain curves for 37-strand AAC.

The results of the tests are used to generate creep-versus-time curves. On the stress-strain graphs, creep curves are often shown for 6-month, 1-year, and 10-year periods. Figure 14-27 shows these typical creep curves for a 37-strand 250- to 1033.5-kcmil AAC. In Fig. 14-27, assume that the conductor tension remains constant at the initial stress of 4450 lb/in². At the intersection of this stress level and the initial elongation curve, 6-month, 1-year, and 10-year creep curves, the conductor elongation from the initial elongation of 0.062% increases to 0.11%, 0.12%, and 0.15%, respectively. Because of creep elongation, the resulting final sags are greater and the conductor tension is less than the initial values.

Creep elongation in aluminum conductors is quite predictable as a function of time and obeys a simple exponential relationship. Thus, the permanent elongation due to creep at everyday tension can be found for any period of time after initial installation. Creep elongation of copper and steel strands is much less and is normally ignored. Permanent increase in conductor length due to heavy load occurrences cannot be predicted at the time a line is built. The reason for this unpredictability is that the occurrence of heavy ice and wind loads is random. A heavy ice storm may occur the day after the line is built or may never occur over the life of the line.

Sag-Tension Tables. To illustrate the result of typical sag-tension calculations, Tables 14-18 to 14-21 present initial and final sag-tension data for 795-kcmil 26/7 ACSR Drake, 795-kcmil, 37-strand AAC

Arbutus, and 795-kcmil Type 16 SDC Drake conductors in NESC light and heavy loading areas for spans of 1000 and 300 ft. Typical tension constraints of 15% final unloaded at 60°F, 25% initial unloaded at 60°F, and 60% initial at maximum loading are used. The calculations in these tables were performed with the Alcoa SAG10™ program, version 1.1.

Initial versus Final Sags and Tensions. Rather than calculated as a function of time, most sag-tension calculations are based on initial and final loading conditions. Initial sags and tensions are simply the sags and tensions at the time the line is built. Final sags and tensions are calculated assuming that (1) the specified ice and wind loading has occurred and (2) the conductor has experienced 10 years of creep elongation at a conductor temperature of 60°F at the user-specified initial tension.

With most sag-tension calculation methods, final sags are calculated for both heavy ice/wind loads and for creep elongation. The final sag-tension values reported to the user are those with the greatest increase in sag.

ACSR Sag-Tension Calculations. Sag-tension calculations for ACSR conductors are more complex than those for AAC, AAAC, or ACAR conductors. The complexity results from the different behavior of steel and aluminum strands in response to tension and temperature. Steel wires exhibit neither creep elongation nor plastic elongation in response to high tensions. Aluminum wires do creep and respond plastically to high stress levels. Also, they elongate twice as much as steel wires do in response to changes in temperature. Table 14-18 presents various initial and final sag-tension values for a 600-ft span of an ACSR Drake conductor under heavy loading conditions. Note that the tensions in the aluminum and steel components are given separately. In particular, some other useful observations are

1. At 60°F, without ice or wind, the tension level in the aluminum strands decreases with time as the strands permanently elongate as a result of creep or heavy loading.
2. Both initially and finally, the tension level in the aluminum strands decreases with increasing temperature (212°F), reaching zero tension at 167°F for initial and final conditions, respectively.
3. At the highest temperature (212°F), where all the tension is in the steel core, the initial and final sag and tension values are nearly the same, illustrating the fact that the steel core does not permanently elongate in response to time or high tension.

TABLE 14-18 Sag and Tension Data for 795 kcmil 26/7 ACSR Drake Conductor
Span = 600 ft; NESC heavy loading district; creep is not a factor.*

Temperature, °F	Ice, in	Wind, lb/ft ²	<i>k</i> , lb/ft	Resultant weight, lb/ft	Final		Initial	
					Sag, ft	Tension, lb	Sag, ft	Tension, lb
0	0.50	4.00	0.30	2.509	11.14	10153	11.14	10153
32	0.50	0.00	0.00	2.094	44.54	8185	11.09	8512
-20	0.00	0.00	0.00	1.094	6.68	7372	6.27	7855
0	0.00	0.00	0.00	1.094	7.56	6517	6.89	7147
30	0.00	0.00	0.00	1.094	8.98	5490	7.95	6197
60	0.00	0.00	0.00	1.094	10.44	4725†	9.12	5402
90	0.00	0.00	0.00	1.094	11.87	4157	10.36	4759
120	0.00	0.00	0.00	1.094	13.24	3727	11.61	4248
167	0.00	0.00	0.00	1.094	14.29	3456	13.53	3649
212	0.00	0.00	0.00	1.094	15.24	3241	15.24	3241

* See Appendix for more detailed tables.

† Design condition.

Sag change of ACSR at high temperature

When first installed, the aluminum and steel wire components of ACSR are both under tension and elongate equally. Ignoring for the moment any initial creep of the aluminum strands, the tension division between aluminum and steel in Drake ACSR when initially installed at 20% RBS (6300 lb) at 60°F may be calculated.

If the elastic modulus of the steel core is taken as 27 Mpsi and the steel core area is 0.1017 in², then the “spring constant” of the steel core is 2.75 Mlb. If the elastic modulus of the aluminum layers is taken as 8.6 Mpsi and the aluminum strand area is 0.6247 in², then the spring constant of the aluminum layers is 5.37 Mpsi. Given the two “springs” in parallel, the tension division can be calculated as follows:

$$H_A = \frac{6300}{\left(1 + \frac{2.75}{5.37}\right)} = 4165 \text{ lb}$$

And the tension in the steel core is 2135 lb.

If the temperature of this conductor is increased from 60 to 212°F, the unstressed length of the steel core would increase to 600.38 ft = 599.80 [1 + 6.4e - 6(212 - 60)] and the aluminum strand layers would increase to 600.97 ft = 599.80[1 + 12.8e - 6(212 - 60)]. Clearly the unstressed lengths of the steel core and aluminum layers are now different. Reapplying tension to the composite conductor, the steel core must be preloaded to 2598 lb = (0.59ft/600.38)(26e6 × 0.1017 in²) before the tension in the aluminum layers begins to increase. The net result of this behavior is that, at high temperature, the conductor tension in the aluminum strands can become zero. This temperature is commonly called the ACSR conductor “kneepoint” temperature. Beyond this “kneepoint” temperature, the thermal elongation of the ACSR conductor is reduced to a level near to that of the steel core alone, though low levels of compression in the aluminum layers must be considered.

Mechanical Interaction of Suspension Spans

Transmission lines are normally designed in line sections with each end of the section terminated by a strain structure that allows no longitudinal movement of the conductor.⁶⁰ Structures within each line section are typically suspension structures that support the conductor vertically but allow free movement of the conductor attachment point either longitudinally or transversely.

Tension Differences for Adjacent Dead-End Spans. Table 14-19 contains initial and final sag and tension data for a 700-ft (213-m) and a 1000-ft (305-m) dead-end span with an ACSR Drake conductor that was initially installed with the same 6300-lb tension limits at 60°F. Note that the differences between final tensions at 60°F is 260 lb, which is due entirely to the difference in span length. Even the initial tension (equal at 60°F) differs by approximately 880 lb at -20°F and 610 lb at 167°F.

Tension Equalization by Suspension Insulators. At a typical suspension structure, the conductor is supported vertically by a suspension insulator assembly, but allowed to move freely in the direction of the conductor axis. This conductor movement is possible because of insulator swing along the conductor axis. Changes in conductor tension between spans, caused by changes in temperature, load, and time are normally equalized by insulator swing, eliminating horizontal tension differences across suspension structures.

Ruling-Span Approximation. The sag and tension for a series of suspension spans in a line section can be found using the ruling-span concept.^{59,60} The ruling-span (RS) for the line section is defined by the following equation:

$$RS = \sqrt{\frac{S_1^3 + S_2^3 + \cdots + S_n^3}{S_1 + S_2 + \cdots + S_n}}$$

TABLE 14-19 Tension Differences in Adjacent Dead-End Spans for 795-kcmil 26/7 ACSR Drake Conductor

Temperature, °F	Ice, in	Wind, lb/ft ²	<i>k</i> , lb/ft	Resultant weight, lb/ft	Final		Initial	
					Sag, ft	Tension, lb	Sag, ft	Tension, lb
Span = 700 ft; NESC heavy loading district; area = 0.7264 in ² ; creep <i>is</i> a factor.								
0	0.50	4.00	0.30	2.509	13.61	11318	13.55	11361
32	0.50	0.00	0.00	2.094	13.93	9224	13.33	9643
−20	0.00	0.00	0.00	1.094	8.22	8161	7.60	8824
0	0.00	0.00	0.00	1.094	9.19	7301	8.26	8115
30	0.00	0.00	0.00	1.094	10.75	6242	9.39	7142
60	0.00	0.00	0.00	1.094	12.36	5429	10.65	6300
90	0.00	0.00	0.00	1.094	13.96	4809	11.99	5596
120	0.00	0.00	0.00	1.094	15.52	4330	13.37	5020
167	0.00	0.00	0.00	1.094	16.97	3960	15.53	4326
212	0.00	0.00	0.00	1.094	18.04	3728	17.52	3837
Span = 1000 ft; area = 0.7264 in ² ; NESC heavy loading district; creep <i>is not</i> a factor.								
0	0.50	4.00	0.30	2.509	25.98	12116	25.98	12116
32	0.50	0.00	0.00	2.094	26.30	9990	25.53	10290
−20	0.00	0.00	0.00	1.094	18.72	7318	17.25	7940
0	0.00	0.00	0.00	1.094	20.09	6821	18.34	7469
30	0.00	0.00	0.00	1.094	22.13	6197	20.04	6840
60	0.00	0.00	0.00	1.094	24.11	5689	21.76	6300*
90	0.00	0.00	0.00	1.094	26.04	5271	23.49	5839
120	0.00	0.00	0.00	1.094	30.14	4923	27.82	5444
167	0.00	0.00	0.00	1.094	30.14	4559	27.82	4935
212	0.00	0.00	0.00	1.094	31.47	4369	30.24	4544

*Design condition.

where RS = ruling span for the line section containing n suspension spans

S_1 = span length of first suspension span

S_2 = span length of second suspension span

S_n = span length of n th suspension span

Alternatively, a generally satisfactory method for estimating the ruling span is to take the sum of the average suspension span length plus two-thirds of the difference between the maximum span and the average span. However, some judgment must be exercised in using this method because a large difference between the average and maximum span may cause a substantial error in the ruling span value.

As discussed earlier, suspension spans are supported by suspension insulators that are free to move in the direction of the conductor axis. This freedom of movement allows the tension in each suspension span to be equal to that calculated for the ruling span. This assumption is valid for the suspension spans and ruling span under the same conditions of temperature and load, for both initial and final sags. For level spans, sag in each suspension span is given by the parabolic sag equation

$$D_i = \frac{w(S_i^2)}{8H_{RS}} \quad (14-77)$$

where D_i = sag in the i th span

S_i = span length of the i th span

H_{RS} = horizontal tension from ruling span sag-tension calculations

Suspension spans vary in length, although typically not over a large range. Conductor temperature during sagging varies over a range considerably smaller than that used for line design purposes.

If the sag in any suspension span exceeds approximately 5% of the span length, a correction factor should be added to the sag obtained from Eq. (14-77), or the sag should be calculated using the catenary method presented in Eq. (14-79). This correction factor may be calculated as follows:

$$\text{Correction} = D^2 \left(\frac{w}{8H} \right) \quad (14-78)$$

where D = sag obtained from parabolic equation

w = weight of conductor, lb/ft

H = horizontal tension, lb

The catenary equation for calculating the sag in a suspension or stringing span is

$$\text{Sag} = \frac{H}{w} \left[\cosh \frac{Sw}{2H} - 1 \right] \quad (14-79)$$

where S = span length, ft

H = horizontal tension, lb

w = resultant weight, lb/ft

Stringing Sag Tables. Conductors are typically installed in line section lengths consisting of multiple spans. The conductor is pulled from the conductor reel at a point near one strain structure, progressing through travelers attached to each suspension structure to a point near the next strain structure. After stringing, the conductor tension is increased until the sag in one or more suspension spans reaches the appropriate stringing sags according to the ruling span for the line section. The calculation of stringing sags is based on the preceding sag equation.

Table 14-21 shows a typical stringing sag table for a 600-ft ruling span of ACSR Drake with suspension spans ranging from 400 to 700 ft and conductor temperatures of 20 to 100°F. All the values in this stringing table have been calculated using the parabolic sag equation with ruling-span initial tensions shown in Table 14-20.

Line Design Sag-Tension Parameters. In laying out a transmission line, the first step is to survey the route and create a plan-profile of the selected right-of-way. The plan-profile drawings serve an important function in linking together the various stages involved in the design and construction of the line. These drawings, based on the route survey, show the location and elevation of all natural

TABLE 14-20 Sag and Tension Data for 795-kcmil 26/7 ACSR Drake 600-ft Ruling Span
NESC heavy loading district; area = 0.7264 in²; creep is *not* a factor.

Temperature, °F	Ice, in	Wind, lb/ft ²	k , lb/ft	Resultant weight, lb/ft	Final		Initial	
					Sag, ft	Tension, lb	Sag, ft	Tension, lb
0	0.50	4.00	0.30	2.509	11.14	10153	11.14	10153
32	0.50	0.00	0.00	2.094	44.54	8185	11.09	8512
-20	0.00	0.00	0.00	1.094	6.68	7372	6.27	7855
0	0.00	0.00	0.00	1.094	7.56	6517	6.89	7147
30	0.00	0.00	0.00	1.094	8.98	5490	7.95	6197
60	0.00	0.00	0.00	1.094	10.44	4725	9.12	5402
90	0.00	0.00	0.00	1.094	11.87	4157	10.36	4759
120	0.00	0.00	0.00	1.094	13.24	3727	11.61	4248
167	0.00	0.00	0.00	1.094	14.29	3456	13.53	3649
212	0.00	0.00	0.00	1.094	15.24	3241	15.24	3241

TABLE 14-21 Stringing Sag Table for 795 kcmil-26/7 ACSR Drake 600-ft Ruling Span
Controlling design condition; 15% RBS at 60°F; No ice or wind, final; NESC heavy loading district.

Horizontal tension, lb	6493	6193	5910	5645	5397	5166	4952	4753	4569
Temperature, °F	20	30	40	50	60	70	80	90	100
Spans	Sag, ft-in								
400	3-4	3-6	3-8	3-11	4-1	4-3	4-5	4-7	4-9
410	3-6	3-9	3-11	4-1	4-3	4-5	4-8	4-10	5-0
420	3-9	3-11	4-1	4-3	4-6	4-8	4-10	5-1	5-3
430	3-11	4-1	4-3	4-6	4-8	4-11	5-1	5-4	5-6
440	4-1	4-3	4-6	4-8	4-11	5-2	5-4	5-7	5-10
450	4-3	4-6	4-8	4-11	5-2	5-4	5-7	5-10	6-1
460	4-5	4-8	4-11	5-2	5-4	5-7	5-10	6-1	6-4
470	4-8	4-11	5-1	5-4	5-7	5-10	6-1	6-4	6-7
480	4-10	5-1	5-4	5-7	5-10	6-1	6-4	6-8	6-11
490	5-1	5-4	5-7	5-10	6-1	6-4	6-8	6-11	7-2
500	5-3	5-6	5-9	6-1	6-4	6-7	6-11	7-2	7-6
510	5-6	5-9	6-0	6-4	6-7	6-11	7-2	7-6	7-9
520	5-8	6-0	6-3	6-7	6-10	7-2	7-6	7-9	8-1
530	5-11	6-2	6-6	6-10	7-1	7-5	7-9	8-1	8-5
540	6-2	6-5	6-9	7-1	7-5	7-9	8-1	8-5	8-9
550	6-4	6-8	7-0	7-4	7-8	8-0	8-4	8-8	9-1
560	6-7	6-11	7-3	7-7	7-11	8-4	8-0	9-0	9-5
570	6-10	7-2	7-6	7-10	8-3	8-7	9-0	9-4	9-9
580	7-1	7-5	7-9	8-2	8-6	8-11	9-4	9-8	10-1
590	7-4	7-8	8-1	8-5	8-10	9-3	9-7	10-0	10-5
600	7-7	7-11	8-4	8-9	9-1	9-6	9-11	10-4	10-9
610	7-10	8-3	8-7	9-0	9-5	9-10	10-3	10-9	11-2
620	8-1	8-6	8-11	9-4	9-9	10-2	10-7	11-1	11-6
630	8-4	8-9	9-2	9-7	10-1	10-6	11-0	11-5	11-11
640	8-8	9-1	9-6	9-11	10-5	10-10	11-4	11-9	12-3
650	8-11	9-4	9-9	10-3	10-9	11-2	11-8	12-2	12-8
660	9-2	9-7	10-1	10-7	11-1	11-6	12-0	12-6	13-1
670	9-5	9-11	10-5	10-11	11-5	11-11	12-5	12-11	13-5
680	9-9	10-3	10-8	11-2	11-9	12-3	12-9	13-4	13-10
690	10-0	10-6	11-0	11-6	12-1	12-7	13-2	13-8	14-3
700	10-4	10-10	11-4	11-11	12-5	13-0	13-6	14-1	14-8

and artificial obstacles to be traversed by, or adjacent to, the proposed line. These plan-profiles are drawn to scale and provide the basis for tower spotting and line design work.

Once the plan-profile is completed, one or more estimated ruling spans for the line may be selected. On the basis of these estimated ruling spans and the maximum design tensions, sag-tension data may be calculated providing initial and final sag values. From these data, sag templates may be constructed to the same scale as the plan-profile for each ruling span, and used to graphically spot structures.

Catenary Constants. The sag in a ruling span is equal to the weight per unit length w times the span length S squared, divided by 8 times the horizontal component of the conductor tension H . The ratio of conductor horizontal tension H to weight per unit length w is the catenary constant H/w . For a ruling-span sag-tension calculation using eight loading conditions, a total of 16 catenary values could be defined, one for initial and one for final tensions under each loading condition.

Catenary constants can be defined for each loading condition of interest and are used in locating structures. Some typical uses of catenary constants are to avoid overloading, ensure that ground clearance is sufficient at all points along the right-of-way, and minimize blowout or uplift under cold-weather conditions. To do this, the following catenary constants are typically found: (1) the maximum line temperature; (2) heavy ice and wind loading; (3) wind blowout; and (4) minimum conductor temperature. Under any of these loading conditions, the catenary constant allows sag calculation at any point within the span.

Wind and Weight Span. The maximum wind span of any structure is equal to the distance measured from center to center of the two adjacent spans supported by the structure. The wind span is used to determine the maximum horizontal force a structure must withstand under high-wind conditions. The wind span is not dependent on conductor sag or tension, only on the horizontal span length.

The weight span of a structure is a measure of the maximum vertical force a structure must withstand. The weight span is equal to conductor weight per unit length times the horizontal distance between the low points of sag of the two adjacent spans. The maximum weight span for a structure is dependent on the design ice and wind loading condition. When the elevations of adjacent structures are the same, the wind and weight spans are equal.

Uplift at Suspension Structures. Conductor uplift, shown in Fig. 14-28, occurs when the weight span of a structure is negative. On steeply inclined spans, the low point of sag may fall beyond the lower support. This indicates that the conductor

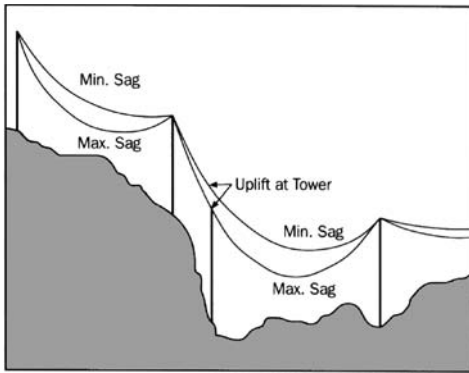


FIGURE 14-28 Illustration of conductor uplift.

in the uphill span is exerting a negative, or upward, force on the lower tower. The amount of this upward force is equal to the weight of the conductor from the lower tower to the low point in the sag. If the upward pull of the uphill span is greater than the downward load of the next adjacent span, actual uplift will occur and the conductor will swing free of the tower. This usually occurs under minimum temperature conditions and must be dealt with by adding weights to the insulator suspension string or using a strain structure.

Tower Spotting. Given sufficiently detailed plan-profile drawings, structure heights, wind/weight spans, catenary constants, and minimum ground clearances, structure locations can

be chosen such that ground clearance is maintained and structure loads are acceptable. Tower spotting can be performed using a sag template, plan-profile drawing, and structure heights, or numerically, by using one of several commercial computer programs. Tower spotting and optimization of line design parameters are discussed in Sec. 14.1.7.

Unbalanced Ice Loads.^{65,66} The jump of the conductor resulting from ice dropping off one span of an ice-covered line has been the cause of many serious outages on long-span lines where conductors are arranged in the same vertical plane. The vertical spacing required to prevent “ice-jump” trouble may be estimated by static calculations of the differential sag of two vertically adjacent conductors assuming one conductor has ice and the other has no ice. Normally, sufficient clearance is provided to accommodate this sag difference, including a factor for sag error with a margin for switching surge withstand.

Utility practice, based on historically satisfactory field performance, is typically based on the following criteria for vertical phase-to-phase clearance due to ice:

A maximum sag error of 6 in is assumed.

The upper conductor is assumed to be subject to maximum ice load, typically 1 in for short ruling spans, 0.5 in for unusually long spans.

The lower conductor is assumed to be completely free of ice.

Clearance sufficient to withstand the maximum switching surge is to be provided.

The calculation is performed using normal sag-tension procedures. For certain line designs (e.g., compact lines with post insulators), dynamic techniques are possible.^{44,50} However, the trouble has been practically cleared up by horizontally offsetting the conductors from 18 in to 3 ft on medium-voltage lines. The conductor jumps in practically a vertical plane, and this should be true if no wind is blowing, since then all forces and reactions are in a vertical direction.

Wind-Induced Motion of Overhead Conductors. In addition to ordinary “blowout” of overhead conductors (i.e., the swinging motion of the conductor due to the normal component of wind), there are three types of cyclic wind-induced motion that can be a source of damage to structures or conductors or that can result in sufficient reduction in electrical clearance to cause flashover. The categories of wind-induced cyclic motion are eolian vibration, galloping, and wake-induced oscillation.

Eolian vibration can occur when conductors are exposed to a steady low-velocity wind. If the amplitude of such vibration is sufficient, it can result in strand fatigue and/or fatigue of conductor accessories. The amplitude of vibration can be reduced by reducing the conductor tension, adding damping by using dampers (or clamps with damping characteristics), or by the use of special conductors which either provide more damping than standard conductors or are shaped so as to prevent resonance between the tensioned conductor span and the wind-induced vibration force.

Galloping is normally confined to conductors with a coating of glaze ice over at least part of their circumference and thus is not a problem in those areas where ice storms do not occur. It may be controlled by the use of various accessories attached to the conductor in the span to change mechanical and/or damping characteristics. Specially shaped conductors or conductor accessories which alter the iced conductor's aerodynamic characteristics, particularly those that increase aerodynamic damping, are also effective. The amplitude of galloping motions can be reduced by the use of higher conductor tensions and evidence suggests higher tensions can also reduce the possibility of occurrence. Galloping and eolian vibration occur in both single and bundled conductors.

Wake-induced oscillation is limited to lines having bundled conductors and results from aerodynamic forces on the downstream conductor of the bundle as it moves in and out of the wake of the upstream conductor. Wake-induced oscillation is controlled by maintaining sufficiently large conductor spacing in the bundle, unequal subspan lengths, and tilting the bundles.

Eolian Vibration. As wind blows across a conductor, vortices are shed from the top and bottom of the conductor. The vortex shedding is accompanied by a varying pressure on the top and bottom of the conductor that encourages cyclic vibration of the conductor perpendicular to the direction of wind flow. The frequency at which this alternating pressure occurs is given by the expression

$$f = 3.26 \times \frac{U}{d} \quad (14-80)$$

where U = wind speed, mi/h

d = conductor diameter, in

f = frequency, Hz

For a 1.0-in-diameter conductor exposed to a 10-mi/h wind, the vortex shedding force oscillates at 32.6 Hz. To develop significant amplitudes, there must be a resonance between this oscillating wind force and the vibrating catenary (conductor). The fundamental frequency of vibration of the suspended conductor is in the range of 0.1 to 1.0 Hz. Therefore, the eolian vibration force will be unlikely to excite a fundamental span mode. This is verified by actual conductor performance where significant amplitudes are usually observed for frequencies in the range of 10 to 100 Hz. Practical wind speeds cause vortex shedding forces of greater than 10 Hz, eliminating frequencies below this level, and frequencies above 100 Hz are not present because of the rapid increase in conductor self-damping for these higher frequencies.

The maximum alternating stress resulting in strand fatigue normally occurs at the conductor clamp. The stress is related to the amplitude of conductor vibration and is the amplitude normally measured by field recording devices. Stress and amplitude of vibration can be related by analytical

means such as the Poffenberger-Swart formula.⁶⁷ The amplitude of eolian vibration is fixed by the balance of energy input from the wind-induced vortex shedding forces and the energy loss due to conductor, accessory, and structure damping. The addition of dampers to the conductor has been established as an effective means of control.⁶⁸ Special conductors such as SDC and SSAC⁶⁹ have also been shown effective in reducing the strand stress levels.

Another effective means of limiting vibration fatigue problems is to increase the self-damping of standard conductors by reducing tension. As a practical approximation, stringing conductors to a final unloaded tension of 15% or less at the minimum seasonal average temperature (usually 0 to 30°F) will prevent vibration fatigue problems. Higher tensions are routinely used in areas where the line is parallel to existing lines and the higher tension on the existing line has not resulted in problems. The use of vibration dampers or special antivibration conductors can also allow the use of higher tension levels.

As with single conductors, bundled conductors are subjected to eolian vibration. However, the interaction of conductors in the bundle due to slightly different tensions and increased damping from spacers results in lower vibration levels for bundles than for single conductors in the same wind exposure.

Galloping. Both bundled and single conductors are subject to galloping during or after glaze ice storms. Galloping oscillations occur at frequencies near the fundamental span mode or its second or third harmonic (0.1 to 1.0 Hz) and exhibit maximum amplitudes as large as the conductor sag. While there has been extensive debate concerning the galloping mechanism, and considerable experimental and analytical study, it appears that there presently exist a number of control methods that are effective in reducing the amplitude and incidence of galloping motion. In-span hardware, such as the “detuning pendulum” developed by EPRI,⁷⁰ and the wind damper” developed by Richardson,⁷¹ are effective for existing spans where galloping occurs. The T2 conductor,⁷² developed by Kaiser, and several other hardware devices are available to control galloping in new lines.

In contrast, control methods such as sleet melting by use of high current levels appear to be almost totally ineffective in stopping galloping and can result in annealing damage to the conductor.

Wake-Induced Oscillation. Bundled conductors are subject to wake-induced oscillations with amplitudes and frequencies typically between that of eolian vibration and galloping. The frequencies of oscillation are normally in the range of 1 to 10 Hz, and the amplitudes are in the range of 10 conductor diameters. The modes in which such vibration occurs are considerably more complex than the modes exhibited during either galloping or the almost invisible eolian vibrations. The source of wind energy for wake-induced oscillation is, as the name suggests, the wake from the windward conductor of the bundle which causes the motion of the downwind conductor.

There are three basic approaches to the control of wake-induced oscillation.⁷³ Two involve reducing the input of wind energy, and the third involves detuning the mechanical bundle system to prevent resonance. The methods based on reducing wind energy input to the bundle are bundle tilting and bundle sizing. By tilting the bundle to angles of 20° or more, the downwind conductors are moved to the edge of the upwind conductor’s wake and the energy input is reduced. By keeping the subconductor spacing to the order of 20 times the conductor diameter, the wind energy input to the windward conductor is reduced by being moved to a wake region of reduced intensity. The third commonly used method to control or eliminate wake-induced oscillations is to stagger the length or simply to shorten the average subspan length. This method does not control those oscillations where the bundle moves as a rigid body and is somewhat dependent on the mechanical characteristics of the spacers.

In comparison to the damage that can result from eolian vibration or galloping, field reports of wake-induced oscillation damage are usually of a minor nature, primarily conductor abrasion from clashing and spacer breakage, neither of which normally results in system outages.

14.1.9 Supporting Structures

Types of Supporting Structure. Numerous types of structure are used for supporting transmission-line conductors, for example, self-supporting steel towers, guyed steel towers, self-supporting aluminum towers, guyed aluminum towers, self-supporting steel poles, flexible and semiflexible steel towers and poles, rope suspension, wood poles, wood H frames, and concrete poles. The type of supporting structure to use depends on such factors as the location of the line, importance of the line,

desired life of the line, money available for initial investment, cost of maintenance, and availability of material. Because of the wide conductor spacing required for electrical clearances and insulation, the high tensile stresses used in conductors and ground cables to pull these cables up to a sag which will keep the heights of the structures within reason, the long spans necessary for crossing ravines in mountainous country, and the reliance to be placed on a major trunk line, lines exceeding 345 kV are frequently built of self-supporting steel towers although guyed and rope-suspension structures are increasingly applied. A line built with self-supporting steel towers is very satisfactory in all respects, as it requires less inspection and has a maximum life with minimum maintenance costs. However, high-strength aluminum-alloy towers are available, and their use is on the increase. They have the advantage of better resistance to corrosive atmospheres than steel.⁷⁴ The structural configurations and design details are the same as with steel, with the added problem of greater deflections when stresses are applied owing to the lower modulus of elasticity of aluminum. The effect of long-time creep of aluminum is yet to be determined. Self-supporting steel poles are frequently used in congested districts where right-of-way is limited and short spans are necessary. The advent of EHV has brought a great variety of new structural configurations. Details of some of these have been published. *Electrical World*, Nov. 15, 1965, pp. 95–118, contains outline drawings of 35 towers and six wood-pole H-frame structures as applied to EHV, as well as a tabulation of specification items of EHV lines in the United States and Canada. The *Transmission Line Reference Book, 345 kV and Above*, 2d ed., 1982, published by EPRI,³ contains details of a broad spectrum of 345- through 800-kV structures.

Wood poles are used extensively where they are readily available. Medium- and lower-voltage lines can be built economically with such poles fitted with either steel or wood crossarms. *Wood H frames* composed of two poles tied together at the top with wood or steel crossarms have been successfully used for the higher-voltage lines up to 345 kV. To take full advantage of the transverse strength, such poles can be braced internally for at least a portion of their height with wood X bracing.

Concrete poles have been used in some parts of the world where timber is scarce and where the ingredients for making concrete are readily obtainable. Another advantage is that they are impervious to insect damage and other forms of decay prevalent with wood structures in tropical or subtropical climates. They are generally cast in units, by using standard forms, and transported to the site, although they may be manufactured where used. Concrete poles should always have sufficient prestressed steel reinforcement to take care of the bending stresses due to wind loads, pulls from cables, and the like, in addition to being designed as columns under vertical loads. In all structures conductor configuration and the effect of various forces which may act upon them must be taken into account.

Conductor Spacing and Clearances

Horizontal Configuration. The minimum spacing of conductors on structures where post-type or V-string insulators are used on medium-length spans will generally depend on the least separation that can be used at midspan without the conductors approaching too closely under adverse wind- or ice-loading conditions.

With suspension insulators a different problem exists, as the swing of the insulator string has to be considered and clearances to the structure determined. This will generally give conductors a spacing at the supports which will be greater than the required midspan separation. One typical rule is to calculate the swing of the insulator string, both with the wind on the bare conductor and the wind on the ice-coated conductor with the corresponding vertical loads acting at the point of conductor suspension, to determine which condition gives the maximum deflection. The vertical loads should be taken on a length of span which is two-thirds the span for the horizontal loads. This will allow a certain amount of leeway in using a standard height structure at a location where the ground is lower than at the two adjacent structures. After the length of the insulator string has been determined electrically and the angle of insulator swing calculated, a normal electrical clearance is established to the structure from the deflected position of the conductor, which, when applied to the three conductors in their relative positions, will determine the necessary horizontal separation of the phases at the supports. This separation should then be checked to see whether it is sufficient for the midspan separation required. Midspan separations that will not be subject to flashover if the conductors begin to swing out of step are usually inherent on high-voltage lines owing to the clearances required at the structures. On very long spans

and on the longer spans of low-voltage lines, these spacings may be insufficient. Thomas⁷⁵ proposed a horizontal-spacing formula for the determination of safe midspan spacings in windy territory where gusts and strong eddies might cause wires to start swinging at different periods

$$\delta = \frac{CdD}{w} + A + \frac{L}{2} \quad (14-81)$$

in which δ = horizontal spacing in feet; C = an experience factor discussed later; d = percent sag of the condition to be studied; D = overall diameter of the conductor; w = conductor weight, in pounds per foot, used in calculating d ; A = arcing distance of the line voltage (1 ft/110 kV); and L = length, in feet, of the swinging portion of the insulator string. Thomas proposed an experience factor of 4 for copper and 3.5 for ACSR.⁷⁵ It has since been found that, in areas not subject to frequent violent winds, values of C as low as 1 will provide safe midspan spacings. Thomas was doubtful

whether as to the added $L/2$ distance is necessary, since insulators seldom swing out of step. This doubt seems to have been justified.

Vertical Configuration. Where the conductors are arranged in vertical configuration, the same electrical clearances will apply for the same voltage as for horizontal configuration, but it may be necessary to increase the vertical separation somewhat to prevent the conductors from coming together or approaching too closely at the center of the span when unequal ice-loading conditions occur or the ice falls off a lower conductor first.

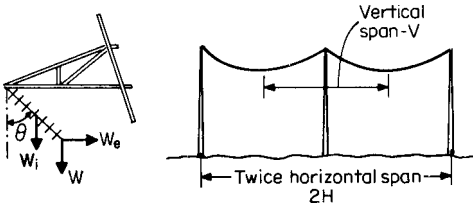


FIGURE 14-29 Determination of suspension insulator swing.

In Fig. 14-29, θ = angle of insulator swing from vertical, H = horizontal span, V = vertical span, w = weight of conductor with or without ice load per lineal foot, and w_i = weight of insulator string including hardware. Then

$$\tan \theta = \frac{Hw_e}{Vw + w_i/2} \quad (14-82)$$

Ground wires, if used, are located above the conductors for lightning protection and in such a position that there is no danger of contact with the conductors at midspan. As ground wires are generally strung with less sag than the conductor cables, ample clearance at midspan is readily obtainable.

These considerations, taken together with the maximum vertical sag to be used and the height required for the conductors above ground level, will determine the height and width of the supporting structure. Extensions can be used where the terrain requires a higher structure than normal.

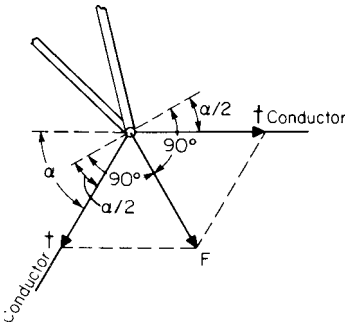


FIGURE 14-30 Determination of transverse forces.

Transverse Forces on Support Structures. Transverse forces acting on towers or poles are due to wind on the conductors and ground cables (and ice coating if in ice districts), wind on the structures, and horizontal components of the tensions in the cables at angle turns in the line (Fig. 14-30).

The stress due to an angle in the line is computed by finding the resultant force produced by the wires in the two adjacent spans. For example, in Fig. 14-30, if the change in the direction of the line is the angle a and the stresses t in the adjacent spans are equal to each other, the resultant force

$$F = 2t \sin \frac{a}{2} \quad (14-83)$$

TABLE 14-22 Resultant Force Due to Equal Tensions of 1000 lb in Adjacent Spans

Angle			Angle		
a deg	$a/2$ deg	Resultant F , lb	a deg	$a/2$ deg	Resultant F , lb
10	5	174.4	70	35	1147.2
20	10	347.2	80	40	1285.6
30	15	517.6	90	45	1414.2
40	20	684.0	100	50	1532.0
50	25	845.2	110	55	1638.4
60	30	1000.0	120	60	1732.0

Note: 1 lb = 4.448 N

Table 14-22 gives the resultant force F due to a tension t of 1000 lb in each conductor of two adjacent spans. The resultant force due to each conductor may be thus computed and the moments about the ground line determined. These moments may be added to those produced by the wind pressure to find the maximum stress.

In applying wind loads to the structure, the appropriate force coefficients, exposure coefficients, and gust response factors should be used.

Longitudinal Forces on Support Structures. Longitudinal forces acting on towers or poles are due mainly to the maximum tension which is assumed to exist in the conductor and ground wires if broken. Ordinarily, especially with suspension insulator strings, these tensions are balanced in the adjacent spans; but if a conductor breaks, a distinct force is produced along the line due to unbalanced tension. If the break occurs on a conductor at the end of a crossarm, there is, in addition to the longitudinal force, a torsional force introduced which must be resisted by the structure. Wind acting in the direction of the line is not ordinarily a factor, as the maximum tension in the conductor is produced when the wind is blowing transverse to the line. As to the reduced stress which occurs in a span from the breaking of a conductor with the suspension insulator string deflecting in the direction of the line, the best practice is to ignore this reduction in tension, as the force due to breaking may cause an impact which more than offsets the reduction in tension. Special release clamps were devised for use on the Plymouth Meeting–Siegfried line of the Philadelphia Electric Company so that, if an insulator string deflected to an angle of 20° in the direction of the line, the clamping mechanism would release the pressure with only the friction in the saddle holding the conductor. This reduced the tension in the conductor considerably; and by assuming a low value for the tension in the conductor due to a break, a more economical structure was obtained.

Vertical Forces on Support Structures. Vertical forces acting on towers or poles are those caused by the weight of that portion of the conductors, plus ice loading if any, which is supported by the structure in question. In addition, there are the weights due to insulators and accessories and the weight of the structure itself. If a structure is located in a valley, there may actually be uplift on it, if the vertical components of the tensions in the conductors exceed the downward loads.

Combined Forces on Support Structures. In determining the maximum forces acting on towers or poles, it is necessary to combine the transverse forces, longitudinal forces (including torsion), and vertical forces so that they act simultaneously. Several different combinations of loading conditions may be desirable, as follows:

1. A condition with all conductors intact and the full transverse and vertical forces acting. These forces should correspond to the appropriate extreme wind and ice loadings and the NESC district loadings. The NESC also specifies overload capacity factors which must be applied to the transverse, vertical, and longitudinal loadings to provide adequate strength of the support

structures. These factors depend on the grade of construction and on the type of structure. ASCE Manual 74⁵⁷ specifies load factors that can be applied to the extreme wind and ice loading cases to increase the reliability for important or long transmission lines.

2. A condition with all conductors intact, except the number it is desired to assume broken, with the transverse and vertical forces computed for each particular conductor, according to whether it is assumed broken. The longitudinal forces due to broken conductors must be combined with the transverse and vertical forces at all points of support where the conductors are assumed broken. It is customary, when more than one conductor is assumed broken, to consider all breaks in the same span and at the supports which will produce the maximum overturning moment, the maximum torque, or a combination of both.
3. A condition in some localities where extraheavy vertical loads, caused by an unusually large formation of ice on the conductors, may occur. These loads are combined with the weight of the structure.
4. A condition with vertical loads acting upward at the conductor supports.

NOTE: It is not customary to combine transverse and longitudinal loads with the loads specified under items 3 and 4.

Other factors may enter into the determination of the maximum forces acting on supporting structures in special cases, such as the horizontal and vertical components of tensions in guys and the addition of pole-top transformers, switches, and working platforms.⁷⁶

The proper number of conductors to assume broken is a debatable question and depends upon what margin of safety is desired and the amount of money it is desired to invest for this security. Generally speaking, the minimum number of conductors to assume broken for tangent suspension single-circuit towers should be either one ground wire or any one conductor, and for double-circuit towers either one ground wire and one conductor or any two conductors on the same side of the tower and in the same span, by using the different cable supports for application of the forces to determine the maximum stress in each member of the tower. Anchor or dead-end towers should be able to withstand all or any number of conductors and ground wires broken. Generally, the condition of broken conductors and ground wires on one side of the tower will produce greater stresses in the web members than if all the conductors and ground wires are considered broken, owing to the unbalanced torsional forces existing when only the conductors and ground wires on one side of the tower are broken.

Types of Metal Structure. Structures may support single, double, or multiple circuits. The first two types are generally used for transmission lines except in congested areas where right-of-way is very expensive and it is desired to transmit large blocks of power over one line. In such a case three or more circuits may be supported by the structures.

Self-Supporting or Rigid Structures. On both single- and double-circuit tower lines of any considerable length, at least three kinds of towers are required for economic reasons:

1. A tangent suspension tower which can be used for normal spans where no angles in the line occur (Figs. 14-31 and 14-32).
2. An angle suspension tower which can be used for normal spans with a small-angle turn in the line or with longer spans on tangents.
3. An angle tower which can be used for normal spans with a large-angle turn in the line, with extra-long spans on tangent, or as a full dead-end tower for anchoring. Insulators may be either suspended or in the strain position.

Very often it is desirable to introduce a fourth kind of tower with insulators always in the strain position to take care of exceptionally large-angle turns in the line; in extremely long spans on tangent; and also, where required, as a full dead-end tower. When this type of tower is provided, the tower listed in item 3 may be of lighter construction and not used for dead-end purposes.

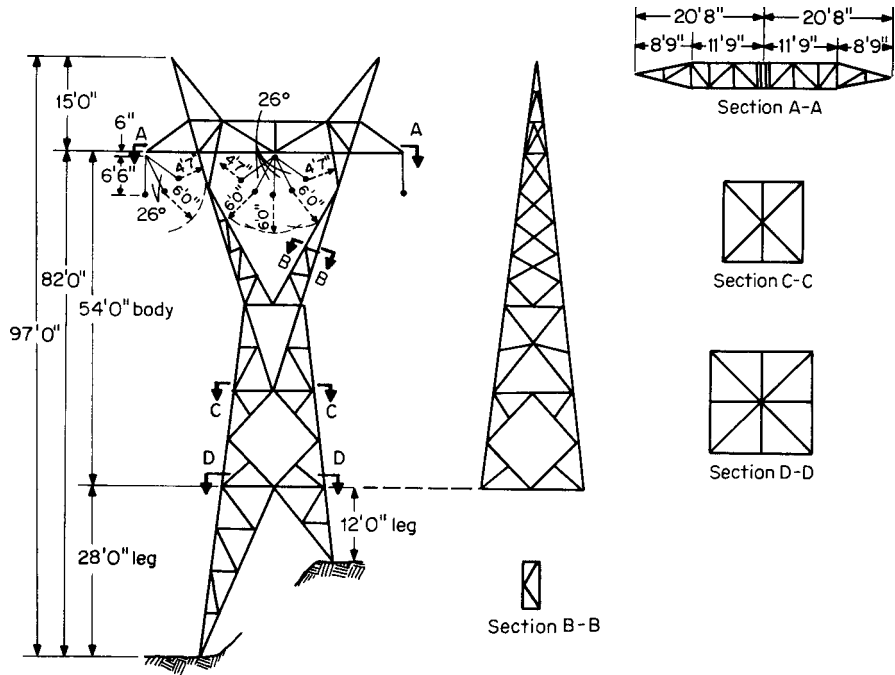


FIGURE 14-31 Tennessee Valley Authority 161-kV single-circuit tangent suspension corset-type tower. (Designed by Blaw-Knox Co.)

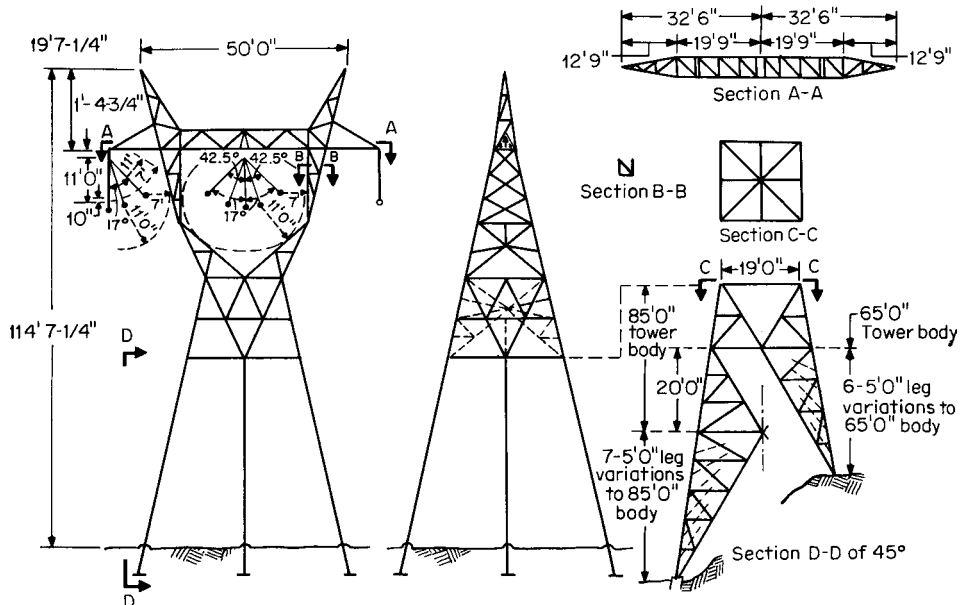


FIGURE 14-32 City of Los Angeles 287-kV tangent suspension rotated-type tower. (Designed by American Bridge Co.)

Double-circuit towers with the vertical configuration of conductors, as used on different lines, are very much alike in appearance, generally being square in cross section. It is customary to locate the middle conductors outside the upper and lower conductors.

With single-circuit towers and the conductors arranged in horizontal configuration, a different problem arises which has resulted in the design of special patented structures for the higher-voltage lines with wide conductor spacing. The shape of these towers has been developed with a view to minimizing the weight of steel required in the superstructure and also reducing the size of footings by minimizing the effect of torsion. The more common types are the Blaw-Knox tower (Fig. 14-31), or corseted type, as originally used on the Plymouth Meeting-Conowingo line of the Philadelphia Electric Company; and the American Bridge Company's rotated tower (Fig. 14-32), used on the first Hoover Dam-Los Angeles line (this line has since been uprated to 500 kV) and also by the Bonneville system and on lines of the Tennessee Valley Authority. Either of these types serves the purpose for which it was intended. The theory behind the rotated tower is that the greatest overturning moment is caused by a combination of the transverse forces and longitudinal forces, due to broken conductors, acting simultaneously, which produces a resultant force acting at an angle of approximately 45° with the direction of the line. In this case the whole four tower legs are resisting the overturning moment, thereby reducing foundation loads and consequently costs. Under normal conditions of loading, with only the transverse forces acting, the legs on the diagonal separation will take care of the overturning moment. Obviously the greatest advantage of the rotated type over the nonrotated type is on tangent towers and towers used for small-angle turns in the line when the transverse and longitudinal forces are approximately equal.

Figure 14-33*a* shows a TVA 500-kV conventional-design tangent self-supporting tower for a bundle-conductor line having three 971,600-cmil ACSR conductors per phase. The overhead ground-wire clamps are suspended and insulated from the tower by means of distribution-type guy strain insulators. The overhead ground wires are composed of seven strands of No. 9 Alumoweld and are used for carrier-current communication channels.⁷⁷ Each ground-wire insulator is provided with a spill-over gap to protect it during lightning discharges.

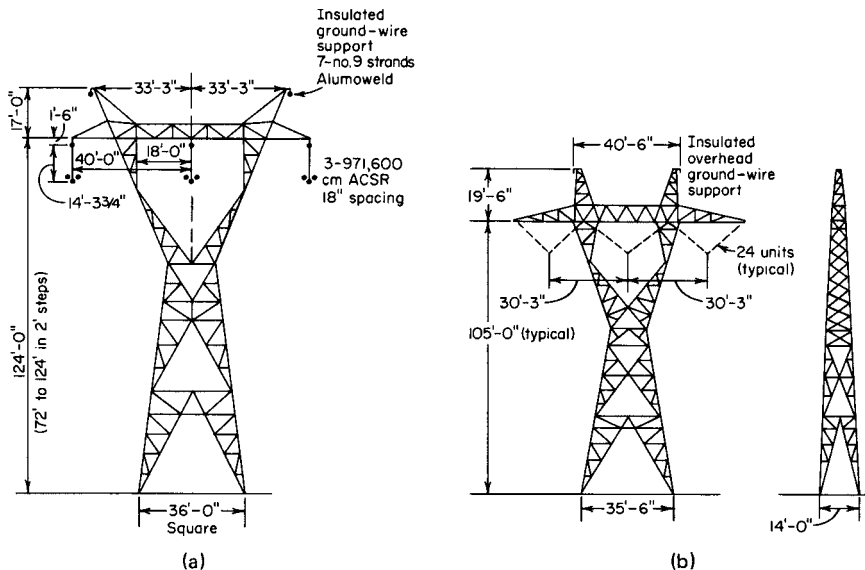


FIGURE 14-33 (a) A 500-kV tangent self-supporting tower (Tennessee Valley Authority); (b) 500 kV semiflexible steel tangent tower (Arkansas Power & Light Co.).

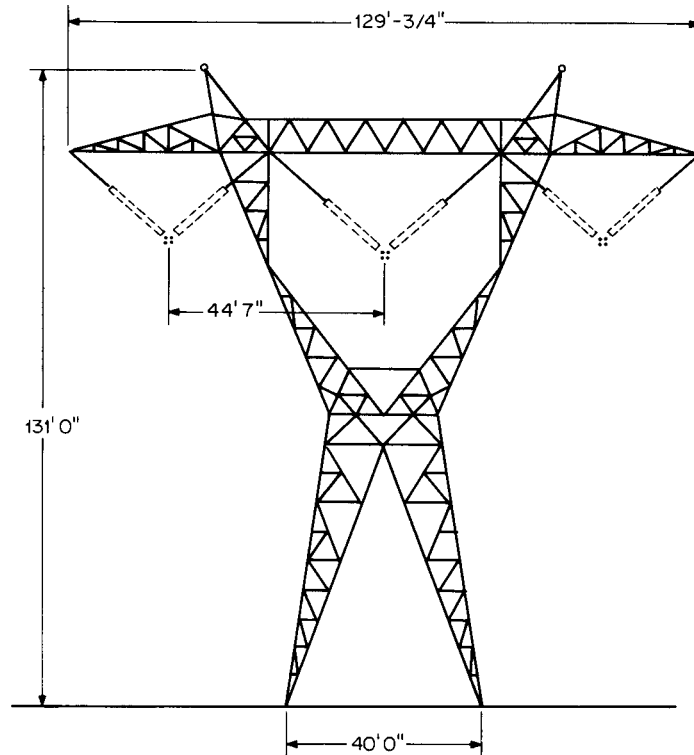


FIGURE 14-36 Steel 765-kV self-supporting suspension tower. (*American Electric Power Co.*)

bundle per phase, where each conductor is a 1,028,000-cmil ACSR insulated with 33 insulator units ($5\frac{3}{4} \times 10$ in) per phase. This type of tower was used on the first stages of the Manicouagan project since September 1965, and in subsequent stages of the same project.

A unique structure is the 765-kV self-supporting steel tower used by American Electric Power Company (Fig. 14-36). This tower, weighing from 44,000 to 66,500 lb, including grillage foundation, was designed by American Bridge Company for erection in parts, if desired, by a Skycrane helicopter. Like AEP's 765-kV V tower shown in Fig. 14-33, there are 30 insulator disks ($5\frac{3}{4} \times 10$ in) per leg of V strings in the outside phases and 32 insulator units in the middle phase. Also, like the tower shown in Fig. 14-33, this tower is designed to meet the same special AEP loading criteria already described. Two overhead ground wires provide a 15° shielding angle to the outside four-conductor bundles.

Semiflexible Structures. Such structures have been used to some extent for the voltages under EHV. This type of tower has a narrow base in the direction of the line. The ground wires are strung tightly to take up unbalanced loads due to broken conductors and form part of the structural system. In case a conductor breaks, the unbalanced load will be taken up by the ground wires and transmitted by them to the next anchor tower.

With the advent of EHV and bundle conductors, semiflexible self-supporting towers are receiving more consideration, and some are being used. With the heavy bundle conductors, the breaking of one conductor is not serious, and the breaking of all conductors of a phase is practically nonexistent. Possible causes are airplanes and tornadoes, which no practical tower could withstand.

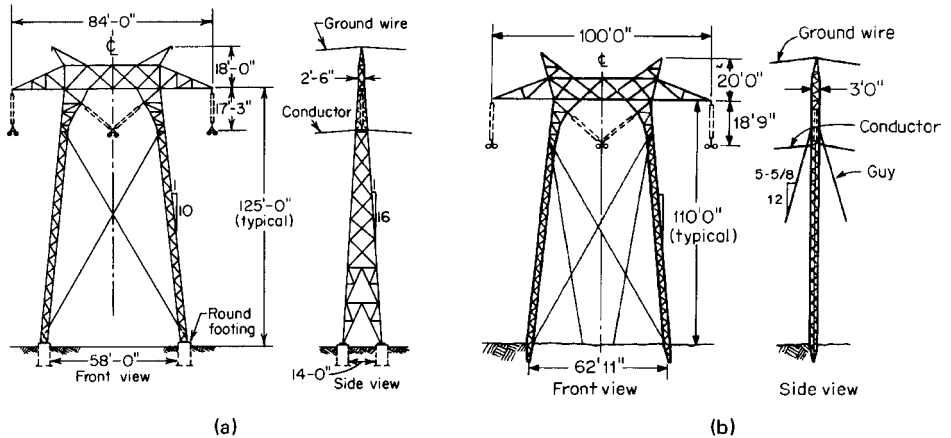


FIGURE 14-37 (a) A 500-kV steel tower used in valley areas (*Pacific Gas and Electric Co.*) (b) A 500-kV steel tower used in mountainous areas (*Pacific Gas & Electric Co.*)

Figure 14-33b shows such a tower as used on the 500-kV system of the Arkansas Power and Light Company. The overhead ground wires are insulated from the towers as they are in Fig. 14-33a for communication purposes. Figure 14-37a shows a steel-saving semiflexible tower used by the Pacific Gas and Electric Company. Note the X guying used between tower legs to obtain the required lateral strength.

Guyed Towers. Such towers overcome the weakness of semiflexible towers in line with the line. They can be used for single-conductor lines or for any other service. Figure 14-37b shows a guyed steel tower used by the Pacific Gas and Electric Company in mountainous country. A feature of the tower is that the legs do not have to be of equal length. This tower has the same internal X guying as the tower of Fig. 14-37a. The self-supporting feature of the tower of Fig. 14-37a is replaced by four guys in the direction of the line and with an increase in strength.

Figure 14-38 shows a Kaiser aluminum guyed-V 345-kV tower used by the American Electric Power Company. Weighing from 3350 to 5400 lb (1510 to 2450 kg), this tower was erected by using a helicopter to “tilt up” the assembled tower by pivoting about a special hinge at the center foundation. This allows the use of a helicopter with a lifting capacity smaller than the weight of the tower since most of the tower weight is supported by the foundation while it is being tilted up. There are 15 insulator units ($5\frac{3}{4} \times 10$ in) per leg of the V strings on this tower.

Figure 14-39 shows a Kaiser aluminum guyed-V 765-kV tower also used by American Electric Power Company. There are 30 insulator units ($5\frac{3}{4} \times 10$ in) per leg of the V strings in the outside phases and 32 insulator units in the middle phase.

Each of these towers has been designed to withstand special AEP loading criteria which include 100-mi/h winds with no ice, 50-mi/h winds with 1 in of ice, and $1\frac{1}{4}$ in of ice with no wind, in addition to the NESC loading requirements.

Tubular Steel Poles. These poles are being used on city streets and in congested areas where a wide right-of-way cannot be gained. They have been used for voltages up to and including 345 kV. Vertical configuration of conductors is used for all high-voltage lines. Insulators may be side post or suspension⁷⁸ on cantilever arms or a combination⁷⁹ of the two. Figure 14-40 shows a 230-kV pole used on a line of the Arizona Public Service Company in Phoenix. These poles are of tubular steel in three sections with telescoping joints. The poles are tapered, with a diameter of 24 in at the base and 10.8 in at the top. The mast arms are 8 ft long, of tubular steel, with brackets bolted to the poles with two $\frac{3}{4}$ -in through bolts. The poles are spaced approximately 300 ft apart. Insulator side swing is reduced by a 200-lb combined hold-down weight and corona shield. The poles present a pleasing appearance and have elicited no objections even with a line installed on each side of a 60-ft street.

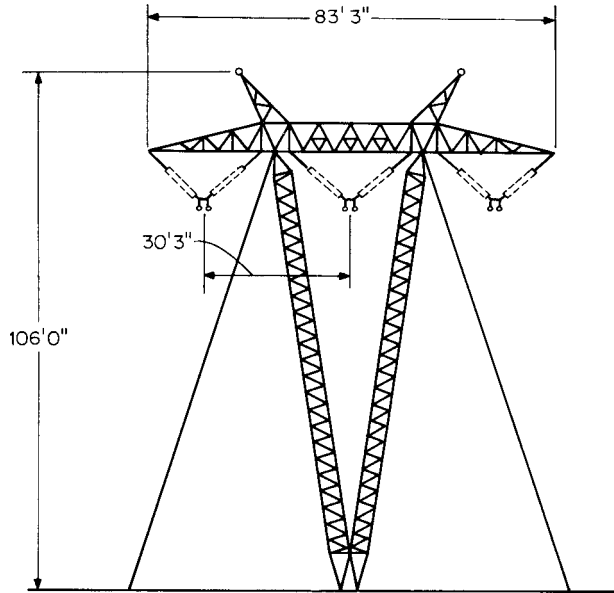


FIGURE 14-38 A 345-kV guyed-V aluminum suspension tower. (American Electric Power Co.)

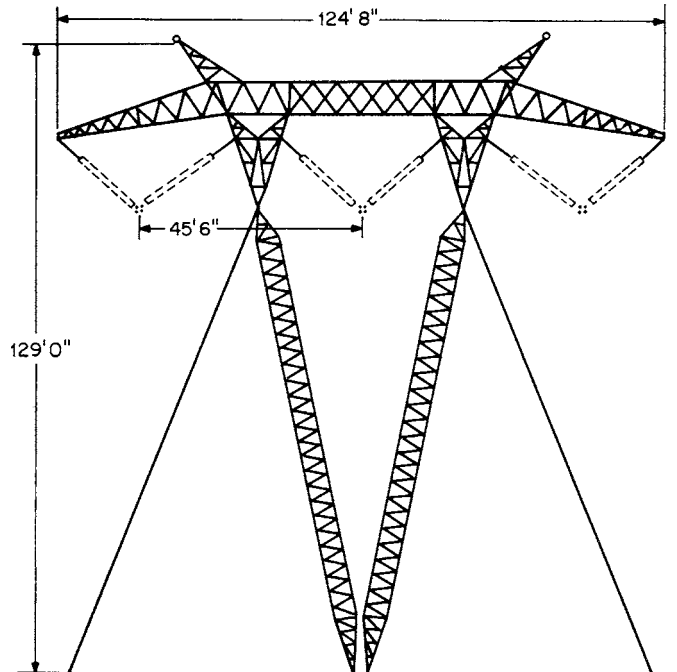


FIGURE 14-39 A 765-kV guyed-V aluminum tower. (American Electric Power Co.)

The poles, side arms, and accessories were furnished by the Union Metal Manufacturing Company of Canton, Ohio.

The New Orleans Public Service Company 230-kV line⁷⁹ is of similar construction but is designed for hurricane-force winds. The poles are 12-sided, elliptical, high-strength steel, with the short diameter, which is in line with the line, 75% of the long diameter. The insulators are a combination of 12 suspension insulators and a swivel-ended strut (side-post) insulator equal to 12 suspension insulators, to prevent side swing of the suspension insulators. Some poles have side-post 230-kV insulators only. The poles have no base for bolting to a foundation but do have baseplates and are set in concrete in holes 25 ft deep. The holes are made by driving 32-in-diameter steel casings to a depth somewhat deeper than 25 ft and cleaning them out.

Special Structures. Transposition towers require special structures where it is not expedient to make the transpositions on a standard tower by the use of special crossarms. Long spans over rivers and bays and crossings over important highways and trunkline railroads frequently require towers which either are much higher than normal or must have a larger factor of safety against collapse. Anchor towers near substations, towers for mounting switches, and towers for turning 90° angles also may come under this classification. Such special structures are designed to suit local requirements and are subject to regulations of the U.S. Army Engineer Corps in the case of navigable-river crossings, to state public-utility commissions or other bodies for highway crossings, and to the particular regulations of railroads which are concerned.

Stresses in Structures—Design. Stresses in towers can be computed analytically by the historic graphic methods or by use of one of the available computer programs for tower analysis and design. Most of the design procedures assume the foundations are rigid. In actual practice, with towers set in the ground, an uneven settlement of the foundations may produce excess stresses which must be considered and taken care of in the overload factor provided against failure. Some flexible lattice-type towers and most pole-type structures will undergo sufficiently large horizontal displacements such that the nonlinear stresses due to the vertical loads acting in conjunction with these displacements (the so-called $P-\Delta$ effect) must be considered in the design.

Tension members may be designed for their full net area of section with bolt holes deducted, and compression members may be designed in accordance with the strength formulas given in ASCE Manual 52.⁸⁰

For short panels in narrow-faced towers, it is economical to use a tension and compression system of web bracing without horizontal struts, as the stresses in the corner posts will be reduced considerably, with torsional stresses eliminated entirely. The bracing should make an angle of 30° to 45° with the horizontal, with all web members in any one panel of the same size to divide the loads equally. Where a tension system of diagonal bracing is used with horizontal struts taking the compression, the angle of the bracing may be increased to 50° or more from the horizontal. Long, unsupported lengths of main members can be broken up by the use of redundant members. The lower panels of towers should be so designed that variable-length leg extensions, which are interchangeable, can be employed to take care of sloping ground. Square extensions of any desired length may be used where towers higher than standard are necessary, with variable-length leg extensions fitted to the bottom of the square extensions if required.

Structure Tests. When an important transmission line is built using structures of new design, at least one type of structure (generally the tangent suspension tower or the type which is to be used most frequently) should be tested, first with the working loads as specified for the design of the tower

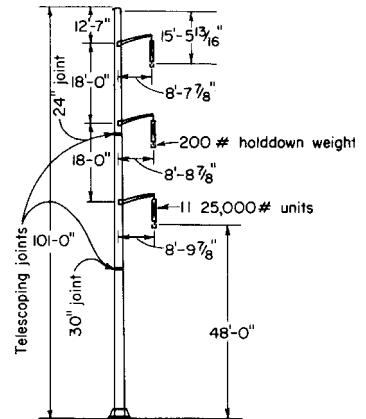


FIGURE 14-40 A 230-kV steel pole. (Arizona Public Service Co.)

applied, and finally with the ultimate loads which the tower is expected to withstand, applied. Steel poles should always be tested on rigid foundations with the transverse, longitudinal, and vertical loads applied simultaneously to introduce all direct bending and torsional stresses. Crossarms should be tested for the additional torsional stresses introduced, where pin insulators are used, and combined with the longitudinal loads and the heaviest vertical loads specified. Equivalent concentrated loads may be used in some cases to avoid applying a multiplicity of small loads at different points, which would cause delay in shifting loads, but care should be taken to see that all combinations of loads or individual loads which will produce the maximum stress in each member are applied. After the structure has successfully withstood all the specified loads, a destruction test is desirable to determine the overload factor. This can generally be made with the test loads which cause the maximum stresses in the greatest number of members on a tower in place, by increasing the transverse loads indefinitely until failure occurs. After a test is completed, members of a tower should be examined for elongation of bolt holes, straightness, etc.

Towers should be tested with the protective coating which is to be used in service on the steel, and the foundations should be the same as those for which the towers are designed. If it is impossible to test towers on earth foundations, they may be tested on rigid foundations, but a test on rigid foundations will undoubtedly show a greater overload factor than may be expected in service.

Erection of Towers. Towers may be assembled on the ground and then lifted into place by means of self-propelled derrick cranes or latticed-steel gin poles.⁸¹ Very large towers are usually assembled in sections, and the sections are lifted into place by means of cranes or gin poles. Towers in inaccessible locations may be transported and assembled by the use of helicopters. If necessary, the towers can be erected from the ground up by the use of gin poles moved from corner to corner and with the erection crew climbing up on the partly completed structure. This method may be used for small jobs which do not warrant the use of heavy cranes or for very tall towers beyond the reach of cranes, such as those for river crossings.

Insulator and Ground-Wire Attachments. (Fig. 14-41). The method of attaching suspension insulator strings varies. One form of attachment is the U bolt fastened on the underside of the crossarm to which the insulator hardware is attached. This device will give flexibility both longitudinally and transversely. Another attachment is in the form of a bent plate or angle fastened to the underside of the crossarm with a fairly large hole to receive a hook or shackle at the top of the insulator string.

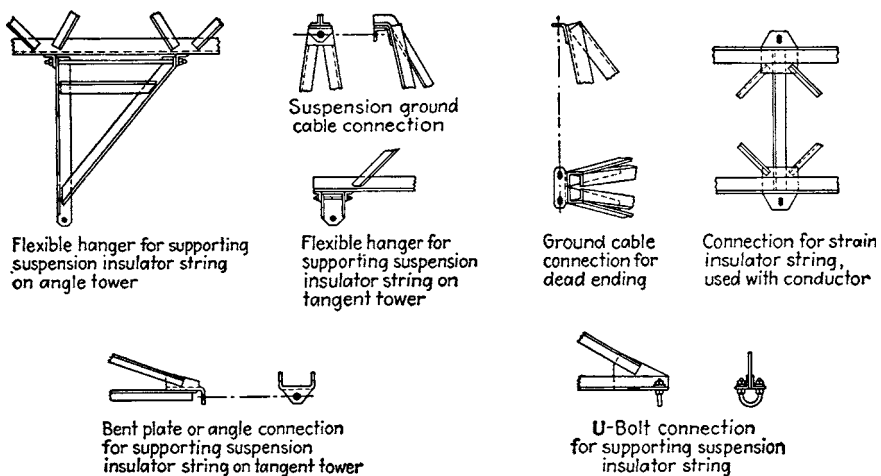


FIGURE 14-41 Insulator and ground-wire attachments.

In order to keep the conductor spacing to a minimum on high-voltage lines and take advantage of clearances to steelwork, the point of attachment of the insulator string may be dropped several inches below the crossarm, in which case flexible hangers are required, that is, hangers which are hinged at the crossarm and free to pivot in the direction of the line. These hangers may be made of plates, shapes, or bent round rods, with suitable connection at the bottom for receiving the insulator string. With suspension-type insulators in the strain position, horizontal pull-off plates are required.

To minimize failure of ground wires due to vibration, they are preferably suspended, and the attachment at the tower consists of an angle or bent plate with a hole to receive the suspension clamp. Patented rigid ground-wire clamps may be obtained if desired, which can be bolted directly to the steel structure. These are generally of the V-groove type.

Ladders and Step Bolts. Ordinary steel towers are provided with step bolts on one corner post for climbing the tower. Special high structures, such as river-crossing towers, should have ladders extending up to the level of the top crossarm. Such ladders should be provided with guard cages supported on the sides of the ladder.

Seismic Effects. This field is complex,⁸² involving the various disciplines of the seismologist; the special dynamicist, who understands both structures and equipment and their differences; the vibration test engineer, and the designer who is experienced in the practical aspects of the lines and equipment and their function. There are many subtleties which are rarely appreciated by any one person and, consequently, many authorities must be consulted.

As contrasted with substation equipment, transmission-line structures built to withstand above-ground weather also will generally survive moderate earthquake tremors without noticeable distress. As studies of seismic effects are becoming more sophisticated, investigators have established seismic design criteria in the United States by dividing the country into four zones of seismic probability, the most severe being on the Pacific coast.⁸³ In such areas periodic review of existing foundations from a seismic standpoint is recommended. Experience in the San Fernando, California, earthquake of February 9, 1971, showed that over the years the foundation strength of a number of towers had been sufficiently reduced by erosion or adjacent excavation that their slopes failed during the earthquake.

One study⁸⁴ analyzes the effect of earthquake ground motion on both wood and steel transmission structures. It concludes that, except where damage to foundations and anchors occurs because actual earth fissures or slippage develop, seismic disturbances produce no overstress in transmission structures designed in conformity with the *National Electrical Safety Code*.

Protective Coatings for Steel Structures

Galvanizing. For important transmission lines where long life is desired, it is almost universal practice to galvanize fabricated-steel towers and poles which are field-bolted after the other shop work has been completed, because under such conditions galvanizing is more economical than painting. The method of "hot-dip" galvanizing is also used for bolts and nuts, with the threads rerun for nuts after galvanizing. This has practically superseded the sherardizing, or "dry galvanizing," of bolts and nuts which was in use for a number of years. All galvanizing should be in accordance with the *Standard Specifications for Zinc (Hot Galvanized) Coatings on Structural Steel Shapes, Plates and Bars and Their Products*, as given by ASTM Designation A 123, which calls for an average coating of 2 oz of zinc per square foot of surface.

To test the uniformity in the thickness of the galvanized coating, the Preece test is used. This is described in the *Standard Methods of Determining Weight and Uniformity of Coating in Zinc-Coated (Galvanized) Iron or Steel Articles*, as given by ASTM Designation A90.

Structures located near industrial plants, if subjected to sulfuric acid and fumes, should not be galvanized.

Painting. Painting is sometimes resorted to for fabricated-steel towers and poles, and generally shop-riveted, welded, or special steel poles are painted. Towers located near industrial plants in a smoky atmosphere should be painted. The base coat should be a mixture of red lead and raw linseed

oil in something like the proportion of 33 lb of dry red lead to a gallon of oil with a little dryer added. The outer coats may be of any good all-weather paint. To keep structures in good condition, painting is necessary every 2 or 3 years. With structures having a larger number of small members, this may make the cost of maintenance very high. On structures having few pieces and large, flat surfaces, painting may be economical.

Where steel structures are buried in the ground, a special problem sometimes arises at the ground level where moisture occurs. At this point, galvanizing may deteriorate after a short interval of time, especially if the soil has a sulfur or acid content. A paint made from asphaltum compounds will often prove useful for protection at these points.

Newly galvanized steel should not be painted until it has a chance to weather for a period of 6 months, and the galvanized surfaces should then be cleaned. Aluminum paint is ordinarily used to paint galvanized towers when the galvanizing has deteriorated.

Weathering, or self-painting, steels have been developed by the major steel companies. These are steels which are not treated with any kind of protective coating, but the chemical composition of which is such that they may be said to "paint" themselves. They are installed completely uncoated but thoroughly cleaned of all mill scale and foreign matter. In a few years, a dense dark-brown oxide with a purplish cast forms which becomes a permanent protective coating to all surfaces exposed to the weather. A slight loss of thickness occurs, which eventually stops, as the corrosion rate is nonprogressive.

Wood Poles. Wood poles are considerably cheaper than steel for many types of construction. The lower cost is due, in part, to the more conservative basis of design normally adopted for steel. Generally, steel structures are designed to support safely one or more broken conductors, whereas wood structures are often not so designed. It is logical that the reasons for choosing the more expensive steel construction should require conservative design throughout and that conditions justifying the cheaper and shorter-lived wood structures would warrant accepting some of the more theoretical hazards.

For voltages of 69 kV and lower, wood is quite generally used.

Wood-pole construction for many years has been used for all voltages up to and including 345 kV. H frames with various modifications have been designed, the most popular using the main crossarm as the bottom member of a truss.

Butt-treated cedar and full-treated pine are used almost exclusively in transmission-line construction; the use of untreated poles has been practically abandoned as uneconomical since the supply of chestnut and northern cedar poles has been exhausted. Treated fir has also been supplied in some quantity from the Northwest.

Cedar poles resist decay, but satisfactory life is not secured unless the butt is treated. The pole is usually treated from the butt to about 2 ft above the ground line. The balance of the pole is not treated. Pine and fir require complete treatment of practically all the sapwood. This treatment is applied under pressure.

No universally effective protection has been devised against woodpecker damage. Some localities are often subject to serious epidemics of woodpecker trouble.

Preservative Treatment. Pole decay is due to a fungus which requires air, moisture, warmth, and food for its subsistence; the wood of the pole constitutes its food. The conditions most favorable to the growth of the fungus are found at the ground line. The preservative has toxic or antiseptic properties which make the wood either poisonous or unfit food for the fungus.

Preservatives and preserving methods conforming to the standards of the American Wood Preservers Association (AWPA)⁸⁵ should be used in the treatment of poles. There are many wood preservatives, including those using poisonous salts such as copper, mercury, zinc, and arsenic compounds. However, only two are included in AWPA recommendations for poles, Standard C-4-74-C:

1. Coal-tar creosote, AWPA Standard P1-65
2. A 5% solution of pentachlorophenol in a petroleum distillate, AWPA Standard P8 (commonly called "penta")

By AWPA Standard M1-70, pentachlorophenol is not recommended for use in coastal waters. Coastal waters are defined as salty waters. One other preservative is increasing in popularity. This is

AWPA Standard P11-70, a creosote-pentachlorophenol mixture in which pentachlorophenol is not less than 2% of the mixture. All of these preservatives are applied by the following methods:

1. *The open-tank method*, applied to cedar poles, consists in boiling the butts of the poles in a tank of creosote oil, after which the oil is allowed to cool or the poles are transferred to a cold tank of oil. The duration of the hot and cold treatment, usually 8 h or more, depends on several factors, the most important of which is the degree of seasoning. The treatment is based on the fact that the wood cells expand with heat and on cooling draw the creosote into the wood under atmospheric pressure. The sapwood of unseasoned poles has annular rings of a nearly impervious fiber which prevent penetration of the oil. In seasoning, this fiber dries and breaks open. To ensure penetration of the greater part of the sapwood, which is usually less than 1 in in depth, an incision process has been developed and is almost universally used. Narrow cuts, parallel with the wood fibers, are made to a depth of about $\frac{1}{2}$ in at frequent intervals around the circumference of the pole for a distance above and below the ground line. Complete penetration is obtained to a depth somewhat greater than the depth of the incisions even on unseasoned poles.
2. *Pressure treatment* is applied to pine and fir. The poles, on a truck, are run into a steel cylinder and subjected to a steam treatment for a period of several hours at a temperature which will not damage the wood cells, usually specified at not more than 259°F (126°C). The pressure is then removed and a vacuum applied. The steam treatment opens up the wood cells and allows the preservative to penetrate. The length of time required for the steam and vacuum treatment depends on the condition of the wood, the amount of oil that is to be injected, and the depth of penetration desired. From this point in the process, one of two methods may be followed. The *full-cell*, or *Bethel*, *process* allows all the preservative injected to remain in the wood. This process is generally used for piling and underwater work when it is desired to exclude water from the wood and to resist the attack of marine borers. The *empty-cell process* draws off excess oil and secures protection from decay by the coating of oil left on the walls of the wood cells. The empty-cell process is adequate and preferable for usual structures and is used almost exclusively for poles and arms.

The empty-cell treatment is obtained by either the Rueping or the Lowry process. The Rueping process seems to be in more general use, although the Lowry process is equally successful.

In the *Rueping process*, following the steam treatment, an air pressure is applied. While still under pressure, hot oil is forced into the cylinder. The oil is held under this pressure and maintained at a temperature of about 200°F (93.5°C) by steam coils within the cylinder, for a period of several hours. Upon removing the oil and reducing the pressure, the compressed air within the wood cells forces out the surplus oil. The amount of oil retained depends on the pressures applied and the time of treatment, although it is possible to remove only a part of the oil that has been injected.

The *Lowry process* is similar to the Rueping process except that no compressed air is used. After the preservative has been forced into the wood under pressure, a high vacuum is quickly created, causing a sudden expansion of the air within the wood cells and thus driving out surplus preservative (see also Sec. 4).

Strength Calculations. As used in a line, the pole is a cantilever beam, fixed in the earth at the butt and supporting the transverse wind load from the conductors of a length equal to half the sum of adjacent spans. Computation of the safe load that may be carried is a matter of simple mechanics outlined in Fig. 14-42. Some slight approximations have been introduced for simplicity.

The fact that if the pole were a part of a perfect cone, the maximum fiber stress might occur at a point above the ground line is of more theoretical interest than practical use. The difference between the load carried at the critical section and at the ground line is less than may readily be caused by irregularities in the pole.

Poles are almost universally classified according to the ANSI dimensions (see Sec. 4), which have been arranged so that the nominal ultimate strength is the same for all lengths and species of the same class. Poles are classified as Class 1, 2, 3, etc., and H1, H2, H3, etc., and the minimum circumference 6 ft from the butt is specified for each class and each species to give the desired nominal strength. The nominal ultimate was computed from conservative average ultimate fiber stresses from a very large number of tests.

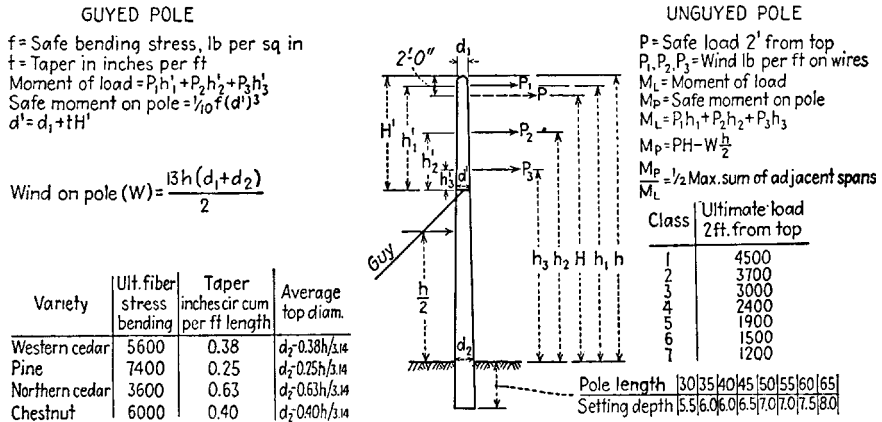


FIGURE 14-42 General pole-strength calculations.

The top diameters are specified but are given only as a minimum and are the same for all species. Actually, the taper of various kinds of timber, although fairly uniform, is quite different for different species, and the average top diameter of ANSI-class poles will be considerably larger than this minimum.

1. *Pole tests.* These give very erratic results, and tests on a few poles should never be given great consideration. Designs should if possible be based on accepted average unit fiber stresses rather than test results unless a considerable number of duplicate tests can be made and averaged.
2. *Factor of safety.* It has been found from experience with heavy transmission-line construction that a safety factor of 2 on the accepted average ultimate is conservative. On light construction, this is sometimes slightly reduced, but a material reduction is usually not justified in view of the deterioration of wood with age. On sustained loads, such as heavy angles, a liberal additional factor of safety is desirable to prevent the pole's warping and giving the appearance of being overloaded. When possible, guys should be attached close to the load to eliminate heavy continued bending.

Setting Depth. The strength of the pole foundation is difficult to reduce to figures and is not of such primary importance to the safety of the structure as in the design of a tower. Failure of the foundation, in the sense that failure is used in the design of steel towers, that is, a considerable movement of the pole in the ground, is of little consequence except for the inconvenience and expense of straightening up the line and retamping the poles. The setting depth for poles of various lengths has been pretty well established by general practice and is almost universally used (see Fig. 14-42). These depths seem somewhat illogical in that no account is taken of the strength of the pole or of the quality of the soil; however, this appears more reasonable when it is considered that the desired result is not to obtain a rigid foundation but to prevent the pole from "kicking" out of the ground.

Wood Crossarms. These are generally manufactured of creosoted yellow pine or untreated Douglas fir. Untreated pine arms of the timber commercially available are not satisfactory. Untreated fir arms are widely used and are apparently giving a life comparable with that of the poles. Arms should be of the highest-quality timber. The smaller arms, up to 5×6 in and 10 or 12 ft in length, can generally be supplied on standard crossarm specifications, although structural specifications give very satisfactory arms. Heavy arms for H frames, that is, 6×8 - and 6×10 -in timbers and 3×8 - and

3- × 10-in planks, 20 to 35 ft long, are best purchased as high-grade structural timbers. Structural timbers are furnished under the rigid specifications and inspection of the large timber manufacturers' associations.

Plank Arms. The eccentric connection of large arms to the pole, especially when carrying heavy conductors, is not desirable, and a number of designs make use of two planks, one on each side of the pole attached together at the ends. Generally two 3- × 8-in planks are used in place of a 6- × 8-in timber arm. The plank-arm construction has several advantages in addition to the better connection to the pole, although the end hardware is somewhat complicated, and in many designs the strength of the crossarm against longitudinal loads is somewhat reduced.

Wood versus Steel Arms. Wood crossarms are lower in cost than steel arms of the same strength and, aside from the shorter life, the possibility of being shattered by lightning, and the risk of burning due to leakage current at 345 kV and above, are satisfactory. On wood pole construction, the advantages of steel crossarms—resistance to lightning damage and longer life—are not usually sufficient to offset the insulation strength of wood crossarms. In any event, lightning damage to arms is usually not a major operating problem; and on lines thoroughly shielded with overhead ground wires, crossarm and pole damage is practically eliminated. At higher voltages, crossarms are sometimes equipped with bonding wires to prevent leakage current from burning.

Design of Arms. The design must provide for carrying the vertical load with an ample margin of safety, but often neither the arm nor the connecting hardware is well suited for carrying the full load of a broken conductor as is required of steel towers. Crossarms on single-pole construction have practically no resistance to longitudinal loads. If a heavy conductor breaks, the arm will swing around to very nearly a longitudinal position, restrained only by the attachment of the unbroken conductors. This would be likely to result in badly bent hardware and probably a split and disfigured arm but little serious damage; the major damage would be the broken conductor and not the effects of the break. H-frame construction (see Fig. 14-46c) is better adapted to such loads, but the effect of a break is much the same, in that the deflection of the poles and movement of the poles in the ground relieve the greater part of the load and usually result in only some minor damage to the arms and hardware, which is easily repaired.

Double-arm construction can be considered very little, if any, stronger than twice the sufficient bolts and keys to develop the shear. The shear is several times the applied load and makes a very heavy joint necessary.

The common sizes used, 5 × 6 in for lighter single-pole construction and 6 × 8 in for H-frame, allow ample vertical strength for ordinary spans. Conservative unit stresses should be used in vertical load on the arms.

The connecting hardware, as generally used, is not designed as would be necessary in a framed structure, such as a truss, where movement in a joint would cause serious secondary stresses in the main members. Only one 3/4-in bolt is ordinarily employed, even in heavy H-frame construction in types of construction carrying wire heavier than has been general practice, and in very long spans the use of these connections, based entirely on experience, should not be followed without a careful check. The same applies to designs carrying heavy angles on crossarm construction where the entire angle load must be transmitted through the bolts to the pole. For such angles, the 3-pole structure is a more positive arrangement.

Conductor Arrangement and Spacing. In wood construction with short spans over comparatively level terrain, these parameters are determined largely by the line voltage. A wide variety of conductor arrangements is found in past practice. However, with the use of larger conductors and longer spans, the conductor configuration and separation are often a matter of providing the safest arrangement with ample spacing, especially for the occasional longer-than-normal spans encountered in rolling country. The conductor arrangement should provide spacing for these occasional long spans, as it is generally more economical to design a standard structure with spacings suitable for a span about 50% longer than normal rather than to use too many special structures.

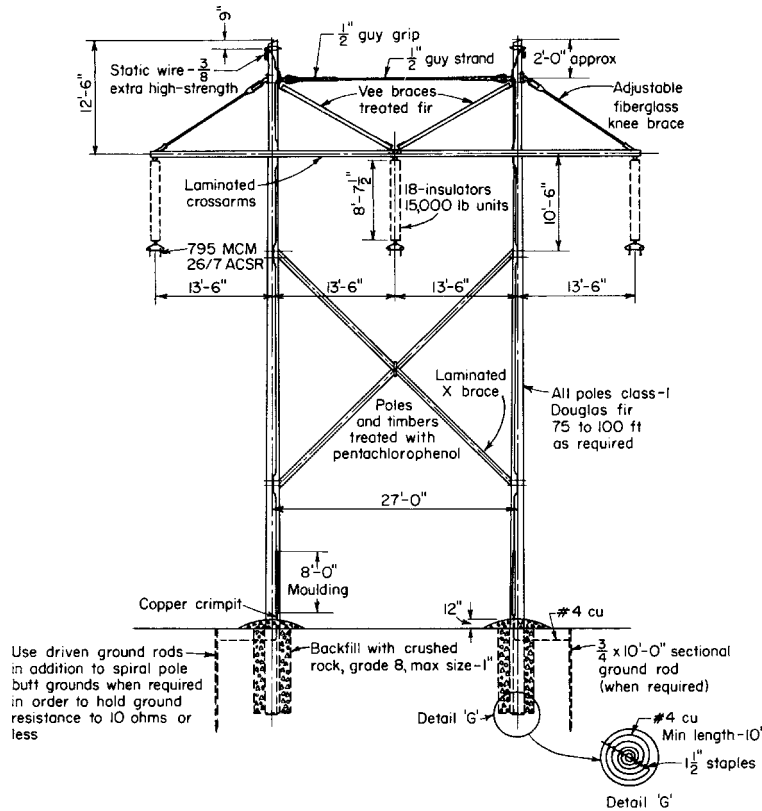


FIGURE 14-43 A 345-kV wood H-frame structure. (Kansas Gas and Electric Co.)

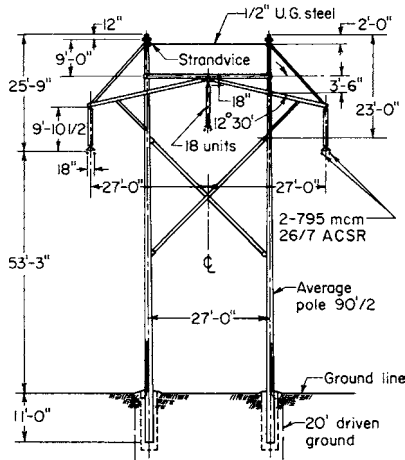


FIGURE 14-44 A 345-kV wood K-frame structure. (Northern States Power Co.)

The H-frame design gives one of the best conductor arrangements and mechanical strength for long-span construction and may be used as a special structure for especially long spans in almost any type of line.

Wood-pole H-frame structures are used on EHV lines at an appreciable saving over metal towers. Figure 14-43 shows an H-frame structure with trussed crossarm as used on the Kansas Gas and Electric Company 345-kV lines. This line uses two 795-kcmil ACSR conductors per phase on 18-in bundle spacing and 27-ft phase spacing. The insulator suspension hardware is not grounded, and full advantage is taken of the impulse insulation of the crossarm. Lightning flashovers would be expected to take place between the conductors and the ground wires on the poles and not to follow the insulator string and crossarm. All poles and timbers are penta-treated fir.

Figure 14-44 shows a modified H-frame wood-pole structure, designated a K frame, as used by the Northern States Power Company on its 345-kV system.⁸⁶ This

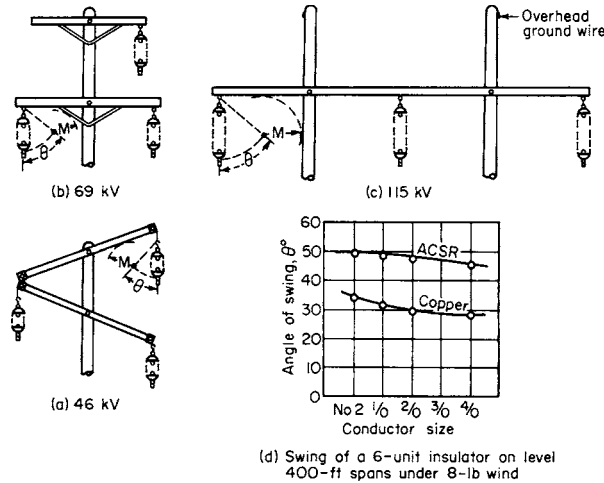


FIGURE 14-45 Typical suspension-insulator arrangements on wood construction.

structure also is designed to carry two 795-kcmil ACSR conductors per phase on 18-in bundle spacing and 27-ft horizontal phase spacing, but the center conductor is approximately 6 ft higher than the outside phases. This structure also takes full advantage of the impulse insulation of the crossarm.

It should be noted that the conductor spacing is primarily a function of the sag and that a conductor arrangement entirely satisfactory for a large or high-strength conductor would be hazardous for a small conductor, with correspondingly greater sags, in the same length of span. Also, a conductor spacing safe for a light loading district should not be used with the heavy sags required for heavy loading conditions. A small or lightweight conductor would require more spacing than a larger or heavier conductor in the same span and with the same sag.

On suspension construction the spacings are usually determined by the clearance required for swing of the suspension insulators as discussed under steel tower design. A detailed layout is required for each conductor, as the size and material have a marked effect on the swing characteristics (Fig. 14-45c). A fairly conservative assumption, which results in reasonable design, requires that the clearance from the conductor to a grounded structure shall be at least 0.75 the dry-flashover distance of the insulator or the "tight-string" distance under an 8-lb wind on the bare conductor at a temperature of 60°F. This may be modified in details, and it is common practice to allow somewhat reduced clearances to wood members. Typical layouts are shown in Fig. 14-45.

The swing should be taken for a somewhat more unfavorable case than level spans. The usual range of conditions encountered would be fairly well covered if a vertical span of three-fourths to two-thirds the horizontal span is assumed; that is, the clearances provide for cases where it is necessary to locate a structure somewhat below the elevation of the adjacent supports.

Angle structures in general use are shown in Figs. 14-46 and 14-47. The design is a matter of providing clearance from the conductor to the structure and to the guys under all conditions and at the same time of attaching guys as close to the load as possible to keep bending stresses down to a conservative value. On small angles where the loads are small, the angle pull may be carried as a bending in the pole and arm; but on larger angles, the loads should be carried directly by the guys, insofar as possible.

Figure 14-46a shows the usual small-angle construction, illustrating how it may be necessary to offset the arms to give clearance to the inside conductor. Figure 14-46b illustrates a similar design for small angles on heavy H-frame construction where the angle is so small that, if the maximum wind should blow from right to left in the illustration, it would cause the insulator to swing somewhat to the left of vertical. Therefore, clearance M must be provided, not only to the pole on the right, in the illustration, but also to the pole on the left. In the above designs the guy is attached some

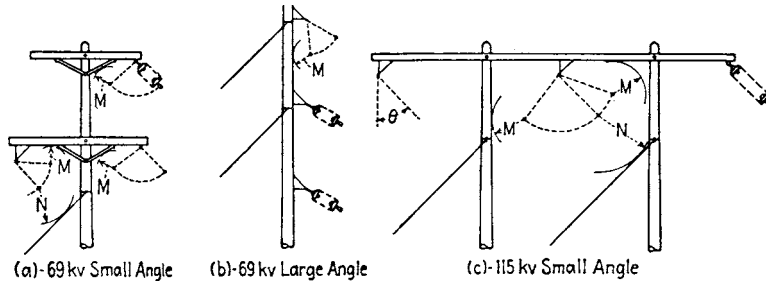


FIGURE 14-46 Suspension-angle structure.

distance below the crossarm in order to give a clearance N from the conductor to the guy, which is somewhat greater than the flashover distance across the insulator. The clearances N and M (Figs. 14-45 and 14-46) indicate the “normal clearance” and “minimum clearance,” respectively. The normal clearance should be at least equal to the porcelain insulator.

The bracket on the pole as shown in Fig. 14-45b is used for larger angles where the mechanical stresses are too great for crossarm construction but for which the angle pull is not sufficient to swing the insulator string away from the pole under a wind from the right or at locations where a heavy vertical load is encountered on an angle structure. A similar 3-pole design is used for H-frame construction. The position of the insulator may be computed for various combinations of loading as shown below.

The simplest angle structure is illustrated in Fig. 14-46. The fewest pieces of hardware and the most direct transfer of stress to the guy are obtained. However, this design can be used only where the angle load is sufficient to hold the insulator string away from the pole under all conditions.

Angles greater than about 50° are usually dead-ended in a structure similar to Fig. 14-47, as it is not advisable to carry too large an angle on the usual suspension clamp. Erection is difficult on large conductors, and guying becomes complicated for very large angles on suspension construction.

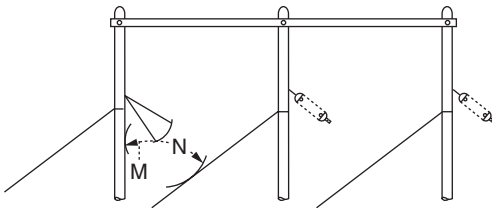


FIGURE 14-47 115-kV large-angle structure.

If grounded guys are used, a ground wire should be carried up the pole; and when the guy is attached close to the insulator, contact should be made with the insulator hardware to avoid the possibility of burning the pole from leakage or splintering from lightning. It is common practice to use one or two additional insulators on such angle structures.

Clearances on angles should be the same as on tangent construction, that is, under normal conditions must be somewhat greater than the flashover distance over the insulator

but under maximum wind conditions may be reduced to 0.75 of normal, with some slight further reduction if this clearance is to ungrounded wood (see Table 14-23).

The greatest swing, that is, angle load and wind in same direction, may occur with wind on the bare wire at 0°F , but usually the combined ice and wind load is limiting because of the larger conductor tension. In the case of the wind blowing against the angle, clearances must be computed for a high temperature and resulting low conductor tension. Under normal conditions, for example, 60°F , full clearance should be maintained, equal at least to the dry-flashover distance of the insulator.

The angle load, that is, the transverse component of the conductor tension t at an angle α , is found as follows:

$$\text{Angle load} = 2t \sin \frac{\alpha}{2} \quad (14-84)$$

$$\tan \theta = \frac{(\text{angle load}) \pm (\text{wind load})}{(\text{vertical load}) + (1/2 \text{ weight of insulator})} \quad (14-85)$$

TABLE 14-23 Clearances for Various Lengths of Insulator String

Insulator, $5\frac{3}{4}$ -in units	Normal clearance, in	Min. clearance 0.75 normal, in
4	$25\frac{1}{4}$	19
6	$36\frac{3}{4}$	27
8	$48\frac{1}{4}$	36
12	$71\frac{1}{4}$	50
16	$94\frac{1}{4}$	70

Note: 1 in = 25.4 mm.

in which θ = swing of the insulator from the vertical; the vertical load is the weight of the conductor supported by the insulator, or the weight per foot times the distance between the low points of the sag in the adjacent spans; and the horizontal load is the wind load on the spans supported by the insulator.

Pole Ground Wires. Ground wires should be installed on all poles, at all voltages, in lightning areas:

1. To prevent splitting of poles by lightning.
2. To provide a direct connection to ground and prevent pole burning if an insulator breaks down. Since the ground wire on these lines has relatively high resistance to ground, the wire can be small as No. 6 galvanized iron and the ground connection can be several wraps of the wire around the butt of the pole.

14.1.10 Line Accessories (Lines under EHV)

Suspension Clamps. These designs are fairly well standardized for the usual conductors. Simple, light, well-designed clamps in both malleable iron and forged steel are available for almost any conductor. The seat and clamping surfaces should be smooth, without any projections or sharp bends, and should be formed to support the conductor on long, easy curves and at the comparatively sharp bends formed at horizontal and vertical angles. Heavy, complicated clamps, unless very carefully designed, are generally avoided to allow as much freedom as possible at the support. For the same reason care is exercised to avoid rigid connections of any kind.

Trunnion-Type Clamps. These are designed to give an almost completely flexible connection by supporting the clamp on a pivot, approximately on the axis of the conductor (Fig. 14-48). Thus any vibration of the conductor tends to be transmitted through the clamp, eliminating much of the heavy binding stresses caused by a fixed support.

The suspension clamp is intended primarily to support the weight of the conductor and to prevent any longitudinal movement from accidental unequal tensions in adjacent spans. It is generally considered desirable but not always essential that the suspension clamp hold the conductor in case of a break. For large conductors under heavy tensions it is difficult to design a light, flexible connection that will not slip under such a contingency.

Slip, or Releasing, Clamps. Several especially heavy lines have been designed on the proposition that, since suspension clamps could not reasonably be secured that would positively hold the conductor, a clamp should be used that would hold under all ordinary conditions but would slip at something like one-half the maximum conductor tension in case of a break. This arrangement justified a considerable reduction in the exceedingly large longitudinal design loads on the towers and resulted in a considerable saving in tower and foundation costs. Several designs of slip clamps and releasing clamps have been used.

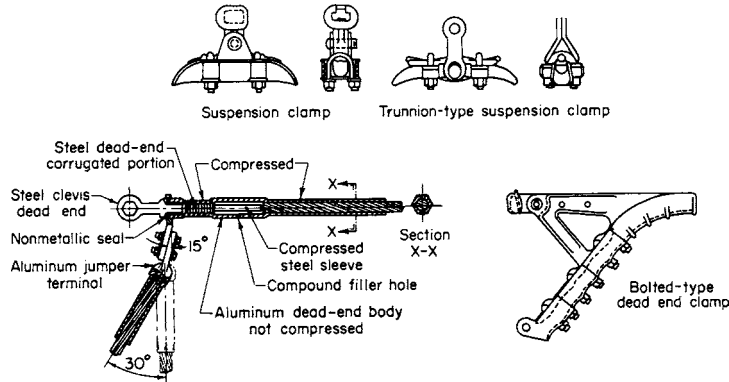


FIGURE 14-48 Conductor clamps.

Dead-End Clamps. These clamps are of the bolted type and are available for practically all copper and aluminum conductors. However, for the larger ACSR conductors the compression-type dead-end clamp is generally used (see Fig. 14-48). This is very similar to the compression splice used on ACSR.

The dead end for the steel core, which may have a clevis or an eye-type end, is pressed on after the aluminum sleeve has been slipped out over the conductor. The aluminum sleeve is then slipped back over the steel sleeve until the aluminum body makes contact with the shoulder of the steel sleeve. The electrical connection tongue on the aluminum body is aligned with the clevis or eye of the steel-core dead end as required, after which the aluminum body is filled with the nonoxidizing compound furnished with the body and the body is compressed. Similar pressed-on dead ends are available for copper, Copperweld, and other conductors. Several manufacturers furnish ACSR dead ends in all sizes required.

Armor Rods. These rods are quite generally used on ACSR lines as a protection against fatigue of the aluminum strands from vibration. Armor rods consist of a bundle of aluminum rods, somewhat larger in diameter than the strands of the conductor, laid parallel to the length of the conductor and arranged to form a complete covering. These are spirally twisted by a tool to lie approximately parallel with the lay of the strands in the cable and are clamped in place at each end. The suspension clamp is attached at the center, with the armor extending 2 or 3 ft on each side. The bending stresses caused by vibration are reduced by the increased diameter and area of metal and distributed over a longer section of conductor.

Vibration Dampers. The Stockbridge damper, as well as several other designs, are devices for damping vibration out of the entire span. Such dampers have been used on ACSR, copper, and steel conductors and ground wires, as illustrated in Fig. 14-49. The cause of conductor vibration and the action of the Stockbridge damper are outlined in the paragraph on wind-inclined motion.

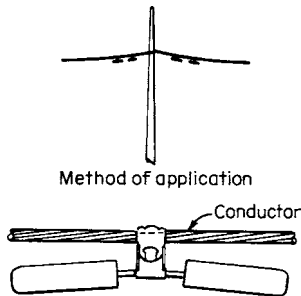


FIGURE 14-49 Vibration damper.

Overhead Ground-Wire Vibration. Overhead ground wires are especially subject to vibration; in fact, most steel ground wires will often be found in rather irregular vibration of small amplitude which generally does not appear to have any ill effects. Ground-wire attachments should be made with at least as great care as given the conductor clamps. Rigid clamps have been almost entirely abandoned in favor of a suspension clamp similar to that used on the conductor and attached by links or shackles so as to give a perfectly flexible connection.

Hardware. Many items of hardware have become fairly well standardized. The dimensions of the eye of eyebolts, the length of thread on various-length bolts, end links, and hardware for suspension insulators are quite uniform. It is usually possible to obtain about identical stock material from a number of manufacturers. Many other items such as shackles, guy clamps, and crossarm braces are furnished in such a wide variety that considerable care is required to choose the most commonly used but suitable stock items. Much expense and confusion in both construction and maintenance are saved by limiting the number of hardware items.

Insulating Braces and Guys. With the use of wood to increase the impulse insulation to decrease the line's sensitivity to lightning flashovers, steel crossarm braces have been replaced with wood on a number of lines. Connections are made by pressed-steel fittings. The use of a 48-in wood brace in place of steel, for additional wood insulation, is roughly the equivalent in lightning-flashover strength of adding one suspension unit to the insulation. The effect on 60-Hz flashover is, however, negligible.

To obtain equal wood insulation at guyed structures to what may be obtained on unguyed construction requires long wood insulators in the guys. These guy insulators are quite efficient because of the high tensile strength of clear wood; an ultimate strength of 6000 lb/in² on the net section is conservative. A 2- × 2-in fir insulator will develop the full strength of a 3/8-in Siemens-Martin guy strand. The design of the connection to the pressed-steel fitting requires only that several bolts of insufficient diameter be used to give the necessary bearing area between the wood and the shank of the bolt. The bolts should be placed alternately through the face and side of the stick to prevent splitting.

Reinforced fiberglass is receiving increased favor as guy-wire insulators in place of wood, and as crossarm braces in place of wood or steel. Impulse flashover voltages of fiberglass line hardware can be supplied by the manufacturers.

Guys. The various grades of guy strand are almost universally furnished in accordance with ASTM specifications. The ultimate strength for each size and grade is given in Sec. 4. The so-called double-galvanized is generally used. Common guy strand is not ordinarily employed in transmission construction, as the best-quality galvanizing is not furnished in this grade. Siemens-Martin strand is most commonly used for the lighter lines and high-strength strands for heavy construction.

More than one size of guy strand is not economical for a line, and often the same size may be used for several designs. The 3/8-in size, in either Siemens-Martin or high-strength grade, is most generally used both for guys and for overhead ground wires.

In the usual wood-pole construction great refinement is not required in designing guys. Usually it is sufficient to determine the number of guys, of the size and quality to be used on the line, required to support the load, an additional guy being employed for any fractional part. In transmission construction a safety factor of 2 is general for guys, although this may be somewhat reduced.

A common problem in guy design is illustrated in Fig. 14-50. The ratio of the guy load L to the conductor load T is the same as the

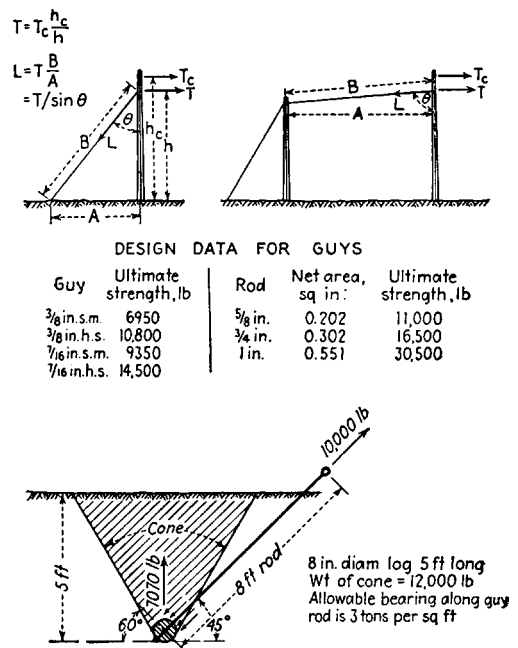


FIGURE 14-50 General guy and log anchor-strength calculations.

ratio of the length of the guy B to the distance A . The length B is readily determined from a sketch drawn to scale.

$$L = T \frac{B}{A} \quad \text{or} \quad L = \frac{T}{\sin \theta} \quad (14-86)$$

If the conductor load T_c is above the point of the attachment of the guy, then

$$T = \frac{T_c h_c}{h} \quad (14-87)$$

14.1.11 Conductor and Overhead Ground-Wire Installation

Conductor Stringing. This operation requires an experienced crew, not only to prevent damage to the conductor and overhead ground wire but also to maintain the sags and tensions specified in the design. Correct sags are essential to give the required mechanical safety, but it is equally important that the actual sag in the line correspond to that used in the design, to ensure proper clearances to the ground. More detailed procedures and guidelines are available in an IEEE publication.⁸⁷

Stringing Equipment. All transmission conductors and overhead ground wires should be strung over free-running snatch blocks or rollers made for this purpose. Both conductors and ground wires of any material are easily damaged, and with the long spans and heavy conductors used in modern construction, satisfactory sags cannot be obtained at reasonable cost except by eliminating all possible friction at the supports. Dynamometers for measuring the tension are of value as a means of knowing the tension at all times, but they cannot be relied on to set the sag. The final sag should be adjusted by sighting. Walkie-talkie radios are widely used as standard erection equipment; better and more efficient work is obtained by having direct communication between the reel crew, the pulling crew, and the workers doing the sagging.

Sags are measured by setting sights on the structures at each end of the span at a vertical distance below the conductor support equal to the sag. This method is convenient and well within the necessary accuracy, even for inclined spans. For average inclined spans, the sag is taken as the sag for a level span of the same horizontal length, although the sag for a level span equal to the slope distance is more nearly correct. Except in extreme cases the horizontal and slope distances are practically the same. On long, inclined spans, when the low point of the sag falls below the ground level of the lower tower, it is more convenient to measure the vertical sag below the lower support.

Accuracy of Sagging. Friction in sagging blocks prevents the wire from reaching exactly the same tension at all points. As the wire is pulled up, the sag tends to be greater in spans from the pulling point; and when slacked back somewhat, more sag is thrown into the nearer spans. These effects are usually fairly well eliminated by allowing some time for the tension to equalize and by skillful handling.

Curves of “span versus sag” and “span versus tension” for possible stringing temperatures are used in sagging. The actual conductor temperature in sagging is very important. The IEEE Committee Report on Stringing and Sagging Conductors, *Trans. IEEE Power Group*, December 1964, p. 1235, recommends that the temperatures be obtained by direct measurement at the time of sagging by means of a thermometer placed inside a short length of the conductor and suspended at least 15 ft above the ground. Accurate temperature also is important in making allowance for creep during stringing. Creep elongation starts as soon as the conductor is pulled into the air, and it is important that this elongation be allowed to take place and not to pull the conductor back up to the calculated sag. One way to do this is to use a temperature curve which will indicate the calculated sag plus the additional sag due to creep up to the time of clipping in. The creep sag must be estimated from the manufacturer’s curves.

In spans of varying length a greater sag tends to form in the long spans; and on steep grades the sags at the higher elevations tend to be less than at the bottom of the hill. These effects are not of importance except in extreme cases and are due to the fact that the wire is, and must be, supported on rollers in such a way as to be entirely free to travel. Thus the tension in the wire on each side of the roller must be equal irrespective of the slope of the wire away from this support, and the resultant on the support is not vertical but in the direction of the bisector of the angle between the slopes of the wires as they leave the roller on each side. At a support between a short and long span (Fig. 14-51) the wire on the short-span side is more nearly horizontal, OA , whereas on the long-span side the wire may have a considerable slope OB . The tension on each side must be equal, $OA = OB$, but the horizontal component of the tension is therefore less in the long span BD than in the short span AE . The resultant OC is inclined.

It is theoretically possible, although very difficult practically, to clamp the conductor at the correct position so that the resultant will be vertical and the horizontal tensions equal as in Fig. 14-51. This is the condition assumed in the computations and office location and, for all except extreme cases, is the reasonable assumption.

Similarly, the different slopes of the wire leaving the roller on hillsides with spans of equal length but at different elevations cause the horizontal component of the tension to be less in the wire with the greatest slope (Fig. 14-52). With a series of spans on a slope this effect tends to accumulate, for the horizontal tension t_2 at the upper support must be the same as the horizontal tension t_2 at the lower support, whereas the resultant tension T_2 is less than the tension T_1 because of its smaller slope.

The differences in sag are not usually carried from one conductor pull to the next, but each pull is sagged to approximately the correct tension independent of the other; thus when the snubs between pulling sections are removed, differences in tension tend to equalize. For this reason it is best not to clamp in the conductors too close behind the sagging crew. Often skillful sagging reduces these effects by using the friction in the blocks to prevent the conductor from "collecting in the low spots."

These irregularities are of little consequence generally, especially when it is realized that the important consideration is to have equal tensions under maximum load rather than under bare-wire conditions. In extreme cases, provision for the above conditions may be made by special sags, allowing somewhat higher tensions in spans above the normal level of the line and providing extra clearance in low sections so that slightly larger than normal sags may be used. Occasionally special methods must be devised.

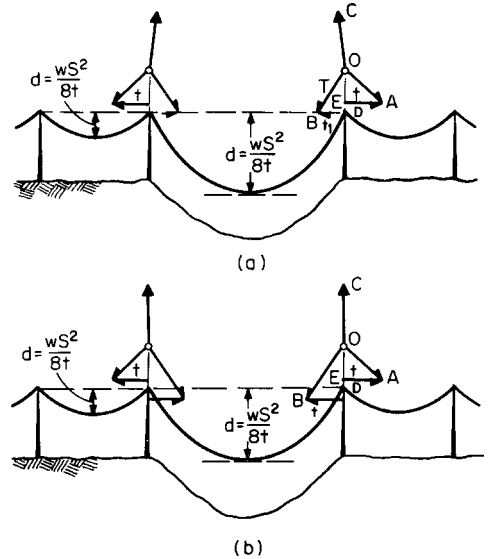


FIGURE 14-51 Diagrams illustrating the change in tension in long spans: (a) on rollers; (b) clamped in theoretically correct position.

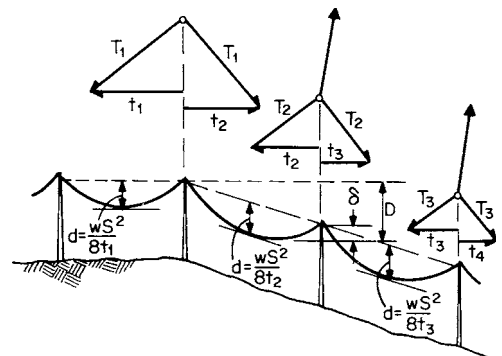


FIGURE 14-52 A much-exaggerated illustration showing the change in tension on hillsides.

Compression Joints. These joints are used with the large ACSR conductors and the large “all-aluminum” conductors, including the high-strength types. As with the compression dead ends, the most widely used joints are those made by Somerset Products Co., a subsidiary of Thomas & Betts Corp., and the Alcoa Conductor Products Co. of the Aluminum Company of America. Cutaway drawings of these joints are shown in Fig. 14-53. They consist of aluminum sleeves and steel sleeves for ACSR. Installation procedures call for the aluminum cable and the insides of the aluminum sleeves to be thoroughly cleaned.

If the conductor is weathered, the strands should be unlayed and all scale removed. The aluminum sleeve is then slipped on the cable and backed out of the way. The aluminum on each cable end is next carefully cut back, care being taken not to nick the steel core, for a distance equal to one-half the length of the steel sleeve plus a distance of $\frac{1}{2}$ in or more, depending on the size of the conductor, so that the elongation of the steel sleeve on compression will not interfere with the free lay of the aluminum strands. The conductor ends are then marked by tape or other suitable means to center the sleeve. The steel sleeve is put in place and compressed, working from the center out. The aluminum sleeve is next slipped into place and filled with the nonoxidizing compound furnished with it, the filler holes are plugged, and the joint is ready for compression. The sleeves are compressed by working from the center out. The center section of the aluminum sleeve over the steel sleeve is not compressed. When the compression is completed, the Alcoa sleeve is hexagonal and smooth from overlapping compressions, and the Thomas & Betts sleeve, also hexagonal, has uncompressed ribs between the compressions as shown in Fig. 14-53.

Overhead Ground-Wire Installation. Overhead ground wires should receive no less care in erecting than the conductors because the usual zinc or copper protective coating is very easily destroyed. Ground wires should be sagged in the same way as the conductors except that the important factor in ground-wire sags is to maintain ample clearance to the conductors. Generally, ground wires are sagged to about 80% of the conductor sags, thus ensuring proper clearance even under ice loads. McIntyre joints are frequently used for splicing, but a much more efficient joint can be made with the pressed-steel joint similar to the ACSR joint illustrated in Fig. 14-53.

In addition to wind and ice loads, overhead ground wires are subject to lightning damage and burning at connection points due to power frequency fault currents. Ground wires are sometimes equipped with jumper connectors at tower attachment points to help bypass fault currents. Three-eighths-inch steel ground wire is reasonably resistant to most lightning currents, but positive lightning strokes, or “winter lightning,” although relatively rare, can heat the stricken point sufficiently to damage the wire or possibly to cause it to separate.

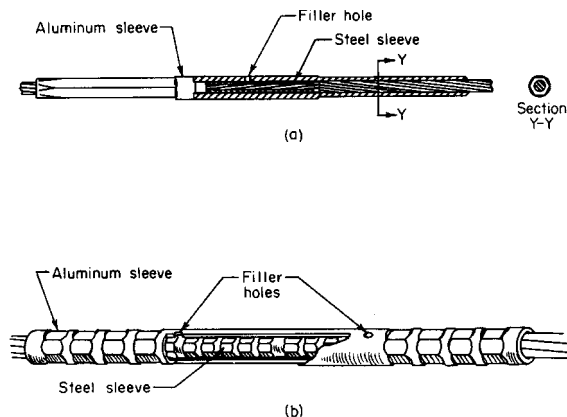


FIGURE 14-53 Compression joints: (a) Aluminum Company of America
(b) Thomas & Betts.

14.1.12 Transpositions

Transpositions^{88,89} are made for the purpose of reducing the electrostatic and electromagnetic unbalance among the phases which can result in unequal phase voltages and currents for long lines. Untransposed lines also can cause inductive interference with paralleling wire communication lines. However, communication interference in the past has been largely with overhead long-distance telephone and telegraph lines. Most of these lines are now going underground, and other overhead lines are being replaced by microwave radio.

For some time, transpositions were little used. With the large power-system networks comprising most of the country's transmission lines, the unbalance of an untransposed line is largely smoothed out by the phase-balancing effect of the rotating equipment scattered over the system. The transpositions, however, do enhance the reliability and efficiency of the line in the following respects: (1) they restrain the amount of current which one line will induce in the other, thereby enhancing the reliability of fault arc extinction in the event of a faulty circuit; (2) they serve to reduce transmission power losses; (3) depending on their location, transpositions can serve to reduce the electromagnetic coupling of power-line currents in adjacent telecommunication lines.

14.1.13 Operation and Maintenance

Operation. Effective operation of a system is as essential to good service as is excellent engineering design. In fact, a well-designed system may fall short of its service requirements owing to faulty operation. Aside from switching lines and power units to meet the load conditions of the system, operation consists not only in restoring service promptly after an interruption but also in detecting and removing faulty apparatus, thus actually preventing the development of faults.

A chief system operator should be in absolute control of the system, and if it is a small system, he or she should have direct communication with and direct control over every part of it. If it is a large system, it will not be possible for one person to supervise all switching operations, and area dispatchers must be located at convenient points. These dispatchers will have the same authority over their areas as the chief system operators for small systems. The area dispatchers will call on the chief system operator not only for approval of unusual switching operations, particularly those involving interruptions to important loads. They will, however, make reports each shift, as convenient, on routine switching operations and will report major interruptions as soon as possible, with cause if known. Dummy boards are useful at dispatching centers. These boards should show the one-line diagrams of the circuits at all stations under the dispatcher's supervision, and provision should be made to show whether switches are open or closed. These boards must be kept correct up to the minute, even if it is necessary to do so by temporary means. It is best to anticipate system changes so that the dummy board can show the changes as soon as they are made. During normal operating conditions no switching should be done, including that of generators, without the dispatcher's permission. All dispatching orders should be reported back in order to prevent misunderstandings and should be recorded in log books both by the dispatcher and by the operator who will do the switching. The logs should show a record of all transactions, with particular care about times of receiving orders, of opening and closing switches, and of cases of trouble.

Emergency routines should be set up for all stations and should be followed at times of catastrophic storms when all means of communication with the dispatcher are interrupted. These routines will list the sequence for doing emergency switching on the operator's responsibility in an effort to restore service.

Supervisory control systems make it possible for operators at one transmission substation to operate several nearby substations as well as their own and thereby reduce operating personnel. Supervisory control also makes it possible for one central dispatching office to operate all the transmission substations serving a large metropolitan area. The supervisor may utilize carrier-current, fiber-optic wires, microwave radio, or telephone channels for transmitting information and operating switches.

Sleet or glaze formation on lines is highly undesirable, and some companies prevent it by raising the temperature of the conductors with current. Ice will form on conductors over a small temperature

range which is on the order of -3 to $+2^{\circ}\text{C}$. The current required to prevent ice formation may be found according to Clem⁹⁰ from

$$I^2 = \frac{\theta \sqrt{dv}}{8.18 \times R} \times 10^4 \quad (14-88)$$

in which I = current, θ = temperature rise in degrees Celsius above surrounding air, R = conductor resistance in ohms per mile at 20°C , d = diameter of conductor, and v = wind velocity in miles per hour.

With the lines in service, it is usually difficult to obtain sufficient current. However, the necessary current sometimes may be obtained by transferring load from other lines to the line in trouble. Dead lines may be heated by short-circuiting them at one end and sending the necessary current from the other end. The approximate voltage to neutral is $E = I\sqrt{R^2 + X^2}$, where R = resistance per wire and X = reactance per wire.

Melting the ice after it has formed is considerably more difficult and requires more current than is required to prevent formation. Clem's article gives the various formulas required to calculate the melting current.

Maintenance. Periodic inspection is normally maintained over all lines, with the frequency of inspection depending on the country traversed and the importance of the lines. In some densely settled areas, patrols of once a week may be considered necessary, whereas important lines in areas subject to heavy storms or other hazards may not require inspections more than once in 2 months. Patrollers may cover the line on foot, on horseback, by automobile, by all-terrain vehicles (ATVs), or by helicopter, depending on the characteristics of the right-of-way. Close and accurate patrolling is not obtained by one person in an automobile, in general, even when the line follows a highway. Helicopter patrol is by far the best over mountainous and sparsely settled country, and 200 mi a day can be covered readily. The helicopter can fly as slowly and as close to the line as is necessary, and it has the great advantage that the patroller is looking down on the line instead of up against the bright sky as a background. Tower and wood-pole structure numbers should be fastened to the tops of the towers or structures in such a manner that they can be read without trouble by the person in the helicopter. Helicopter patrol cannot be used over urban areas or congested industrial areas because of governmental restrictions on height of flight. Patrols on foot are best in such areas. Horseback patrol is best in cattle-range country, if aerial patrol is not available.

Landslides, washouts, danger timber, or anything else that is a potential danger to the line, such as piles of brush or straw which if burned could cause hot gases to short circuit the line, should be reported. Of course the person on patrol must also be on a close lookout for damaged conductors, insulators, and structures. A pair of field glasses is usually considered indispensable.

Personnel on ground patrols should keep the dispatcher informed as to their whereabouts and should call in from all patrol telephone stations and from substations as they reach them. They should call in not less often than morning, noon, and night. If a storm comes up while patrollers are out on a line, they should call the dispatcher as soon as possible, telling where they can be reached. Patrol cars and helicopters are radio-equipped.

Tree gangs whose sole duty is to remove brush, trim trees, and remove danger timber have been found to be advantageous by large companies. The use of chemical sprays to kill brush along rights-of-way is satisfactory from the standpoint of killing the brush if legally permissible but leaves a potential fire hazard. Care must be taken in spraying that wind does not blow the chemicals over growing crops. This danger has been found to be a disadvantage in helicopter spraying.

Emergency crews are stationed at locations always available by telephone or radio so that every important section of the transmission system can be reached by a crew within a reasonably short time. Small houses containing spare parts, such as insulators, lengths of cables, and clamps should be located at intermediate and accessible points along the line in sparsely settled country. Such houses should be kept locked. Some companies employ concrete construction with iron doors. A routine inspection and checking of materials in such houses is advisable. A light truck, provided with two-way radio and with the necessary tools and materials for making immediate repairs, is used by many companies. In addition to spotlights on the truck, a spotlight operated from a portable storage

battery is frequently very useful. Small houses containing spare parts, such as insulators, lengths of cables, and clamps, should be located at intermediate and accessible points along the line in sparsely settled country. Such houses should be kept locked. Some companies employ concrete construction with iron doors. A routine inspection and checking of materials in such houses is advisable.

Line repairs and replacements are accomplished either when the line is energized or deenergized. The line crew should notify the dispatching office when a particular line or section is desired. If deenergized maintenance is desired, the line should then be not merely cleared through the circuit breakers but opened by disconnecting switches as well. If it is to be out of service for an extended period and there is danger of lightning, the line should be grounded out at its terminals to prevent the possibility of flashing over switches or insulators at the terminals. If the line is not equipped with grounding switches, it may be grounded out by equipment such as is used by line crews. Before the line crew is allowed to work, the line should be short-circuited and well grounded on each side of the location where the crew will work, with the grounding equipment in full sight. The grounding equipment should consist of heavy extraflexible copper cables, which should be attached by means of "hot-line" tools and clamps, the line being considered to be "hot" until the grounding equipment is applied. Ground chains are not safe and should not be used. Reliance should not be placed in grounding switches or grounding cables at the ends of the line.

In order to make repairs and replacements without interrupting the service, special "live-line" tools have been devised whereby insulators may be replaced, conductors spliced, etc., on lines of all voltages while the line is hot. Live-line maintenance methods are described in an IEEE Task Group Report⁹¹ of the IEEE Transmission and Distribution Committee (1973). It covers methods and equipment for live-line maintenance. A foundation is presented from which working clearances and methods can be developed for specific needs in particular applications. A bibliography⁹² concerning live-line maintenance is available.

Damaged insulators and insulator sections may be detected while they are in service, but suitable precautions should be followed. In general, the methods employed for faulty-insulator detection are based on the measurement of the voltage gradient across the individual units of a string of suspension insulators or across the parts of multipart pin-type insulators. For safety reasons, none of the test methods should be used in wet weather.

Faulty insulators may also be detected by special radio interference locators consisting essentially of a sensitive battery-operated receiver coupled to either a directional loop antenna or a "whip" antenna. The latter type may be attached to a hot-line stick to enable close investigation of the insulator under test. Infrared techniques are also employed.

The Doble method⁹³ is, in effect, a spark-gap voltmeter which is safe to use and which gives high accuracy in measuring potentials in the field on live transmission-line insulators.

There are two general types of Doble safety tester: the type A single-prong tester for multipart pin-type insulators on either wood or steel construction, and the type B two-prong tester for multiunit suspension-type insulators on either wood or steel construction. The type B is most applicable to transmission lines.

The equipment consists of a micrometer spark gap in series with a capacitor and a special telephone-type headset with which to listen to gap sparkover. The telephone receiver is heard through a rubber hose connected to a highly insulated hollow tube which is long enough so that there is no danger to the operator.

Both sides of the electric circuit of the tester are terminated by exposed metal tips (Fig. 14-54) arranged so as to bridge readily a single insulator disk or section. In the circuit between the two contact tips, a protective insulating capacitor is built into the tester in such a manner as to make the impedance between its terminals greater than the impedance of a single good disk. Thus, in operation, the tester *does not short-circuit* the disk under test. The tester may be considered as a voltmeter which indicates the voltage between the points on the insulator touched by the tips of the tester.

The degree of defect in the disk under test is indicated by the size of the maximum gap at which a noise is heard in the tester, as compared with the size of a maximum gap for a good disk in the same position in a string; a

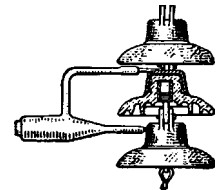


FIGURE 14-54 Doble insulator tester using the principle of a spark-gap voltmeter for suspension insulators.

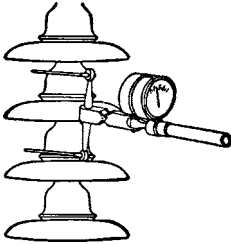


FIGURE 14-55 The I-T-E Imperial Corp. two-prong live-line insulator tester.

totally dead disk gives no sound, irrespective of the gap setting. In practice, one gap length is fixed in advance and used for all units of the string. The operator judges if a unit is defective from the noise heard in the headset. This apparatus is in use for testing insulators on lines at voltages from 11 kV through the medium transmission ranges.

The I-T-E Imperial Corp. live-line insulator tester detects defective insulators, either multipart pin-type or suspension, by comparing the measured voltage distribution over insulators or insulator strings while in service with characteristic curves plotted for good insulators of the same type. It is suitable for use in testing insulator integrity on transmission systems with nominal voltages through 230 kV. The tester employs a single-prong head for multipart pin-type insulators, a small two-prong head (Fig. 14-55) for suspension strings or small one-piece insulators, and a

large two-prong head for multipart pedestal insulators. Visual indication is given by means of a meter which shows a deflection in proportions to the voltage gradient. Since relative indications only are required, the meter is calibrated simply in units of deflection. Tests may be made of all shells of multipart pin-type insulators and all units of suspension strings with equal facility. As with the Doble tester, tests should be made only on perfectly dry insulators.

Doble field power-factor test is used (in contrast to that previously described) for testing the insulation of electrical power apparatus *with the apparatus out of service*. Dielectric watts loss and charging current are measured at selected test voltages up to 20 kV, from which power factor, capacitance, ac resistance, and the presence of ionization (corona) can be determined. The specimens to be tested may be in the substation or in the service building.

The test equipment is capable of determining the condition of electrical insulation of bushings, bus supports, cables, capacitors, circuit breakers, insulators, surge arresters, liquid insulation, potheads, rotating machinery, transformers, and voltage regulators. Power-factor measurements with this equipment have been adopted by many companies as a criterion for servicing power-apparatus insulation.

High power factors or sudden increases in power factor from a previous test indicate contaminated or deteriorated insulation which may be an operating hazard. Changes in the watts loss, charging current, ac resistance, and capacitance between tests are also used for indicating operating hazards in apparatus insulation.

A variety of other makes of portable insulation testers, both ac and dc, are available for use in testing line insulation, if desired, when the line is out of service.

14.1.14 Foundations

Lattice-Tower Foundation Loads and Displacement Criteria. Lattice-tower foundation loads consist of vertical tension (uplift) or compression forces and horizontal shear forces. For tangent and small-line-angle towers, the vertical loads on a foundation may be either uplift or compression. For terminal and line angle towers, the foundations on one side may always be loaded in uplift while the other side may always be loaded in compression. The distribution of horizontal forces between the foundations of a lattice tower vary with the bracing of the structure. A typical free-body diagram of foundation loads is shown in Fig. 14-56.

When the foundations of a tower displace and the geometric relationship of the tower to its foundations remains the same, any increase in load due to this displacement will have a minimal effect on the tower and its foundation. However, foundation movements which change the geometric relationship between the tower and its foundations will redistribute the loads in the tower members and foundations. This will usually cause greater reactions on the foundation that moves least relative to the tower, which in turn will tend to equalize this differential displacement.

Presently, the effects of differential foundation movements are normally not included in tower design. Several options are available should the engineer decide to consider differential foundation displacements in the tower design. These options include designing the foundations to satisfy performance criteria which will not cause significant secondary loads on the tower, or design the tower to withstand specified differential foundation movements.

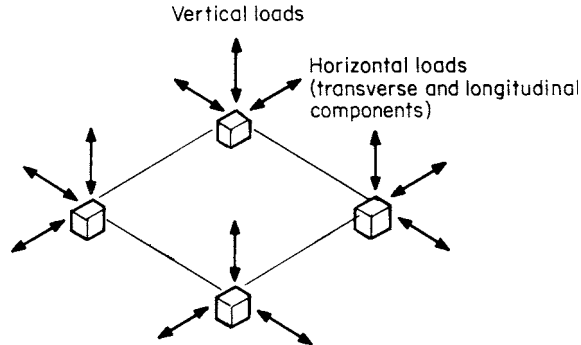


FIGURE 14-56 Typical loads acting on lattice-tower foundations.

Single-Shaft Foundation Loads and Displacement Criteria. Single-pole structures have one foundation so that differential foundation movement is precluded. The foundation reactions consist of a large overturning moment and usually relatively small horizontal, vertical, or torsional loads. Figure 14-57 presents a free-body diagram of the loads.

For single-shaft structures, the foundation movement of concern is the angular rotation of the shaft in the vertical plane and horizontal displacement of the top of the foundation. When these displacements have been determined, the displacement of the conductors can be computed. Under high-wind loading, a corresponding deflection of the conductors perpendicular to the transmission line can be permitted. Accordingly, a large ground-line displacement of the foundation could also be permitted. As a result of foundation rotation, the clearance between the conductors and the structure would be decreased only for structures with single-string insulators. The midspan ground clearance and the change in line angle would also decrease a negligible amount.

In establishing displacement criteria for single-shaft-structure foundations, consideration should be given to how much total, as well as permanent, displacement can be permitted. In some cases, large permanent displacements might be aesthetically unacceptable and replumbing of the structures and/or their foundations may be required. In establishing displacement criteria, the cost of replumbing should be compared to the cost of a foundation that is more resistant to displacement.

For terminal and large-line-angle structures, large foundation deflections parallel to the conductor may be intolerable. For these structures, excessive deflections may reduce the conductor-to-ground clearance or affect the load capacity of adjacent structures. There are also problems in the stringing and sagging of conductors if the deflections are excessive. These problems are usually resolved by designing a more deflection-resistant foundation, construction methods, or use of permanent guys.

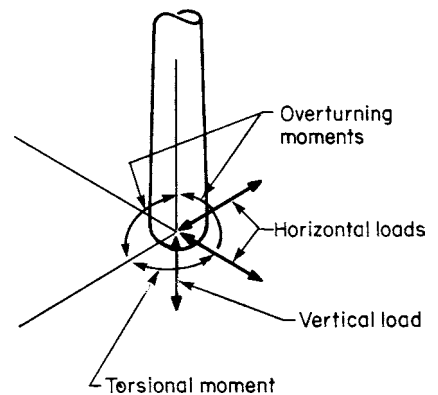


FIGURE 14-57 Typical loads acting on foundations for single-shaft structures.

Framed Structure Foundation Loads and Displacement Criteria. These structures are dependent in part for their stability on one or more of their joints resisting moment. The foundation reactions are dependent on which joints can resist moment and the relative stiffness of the members. Figures 14-58 and 14-59 present free-body diagrams of four- and two-legged framed structures. If the bases of

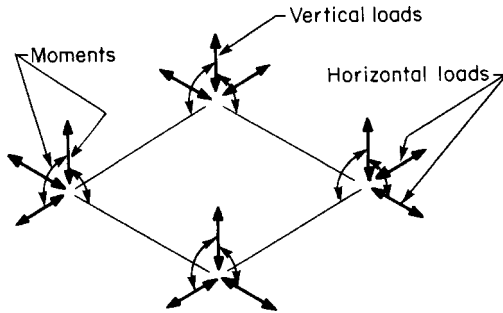


FIGURE 14-58 Typical loads acting on foundations for four-legged framed structures.

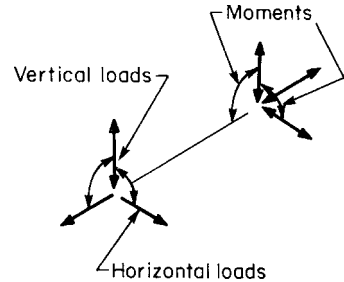


FIGURE 14-59 Typical loads acting on foundations for two-legged framed structures.

structures are assumed as pins or universal joints, then the moments acting on the foundations will theoretically be zero.

Many different types of two-legged, H-framed structures are in use in transmission lines. This has been particularly true since visual impact has become of greater concern.

The H-frame structure is particularly applicable for wood, tubular steel, and concrete poles. The crossarm may be pin-connected to the poles. These structures may be unbraced, braced, or internally guyed as shown in Fig. 14-60.

As with lattice towers, past practice has not usually included the influence of foundation displacement and rotation in H-frame structure design. Significant foundation movements will redistribute the frame and foundation loads. The foundations can be designed to experience movements which will not produce significant secondary stresses, or the structure can be designed to a predetermined maximum allowable foundation displacement and rotation.

Typical HV and EHV Guyed Structures. *Guyed Portal Structures.* The design and utilization of guyed-mast transmission structures (guyed towers) has evolved very rapidly since the mid-1960s or so, and the subject warrants discussion. A high-strength wire stranding used in tension and a latticed mast in compression with limited bending are two of the most efficient structural components, a point not lost on designers of transmission lines in northern Europe during the early days of transmission of electricity.

The most popular form was the guyed portal tower (Fig. 14-61), in which two tripods, each essentially consisting of a mast and two guys, were held apart at the tops by a rigid crossarm. The arrangement permitted the use of two mast footings (compression with a little shear load) and if the structure was not too tall, the four guys could be brought to two anchors, each doing double duty. The structure also offered the possibility of easy ground assembly and erection by one-piece rotation using a gin pole or A frame. Portal tower application was to a large extent limited to flat terrain and relatively short towers (short spans or low voltages) as rough terrain required masts of different lengths, which

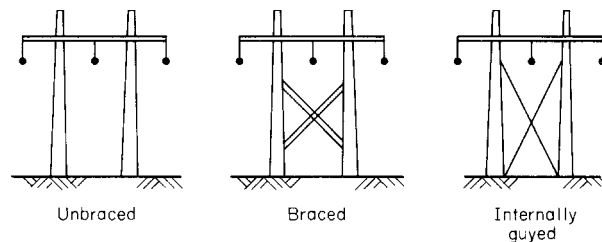


FIGURE 14-60 Typical H-frame structures.

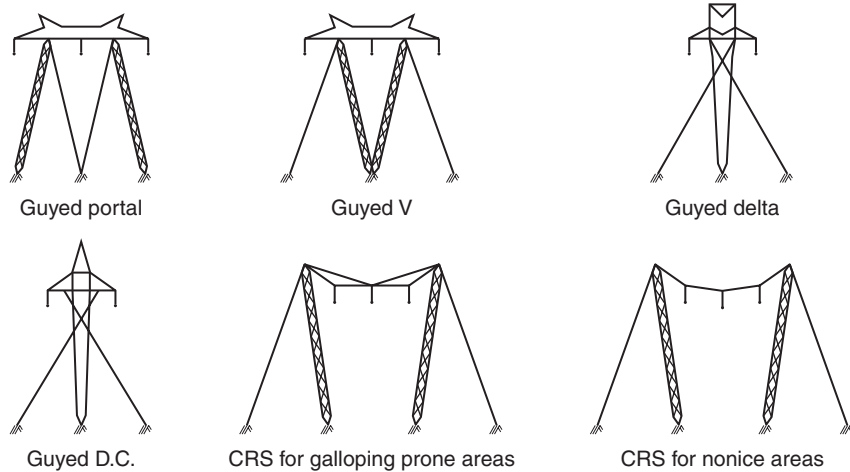


FIGURE 14-61 Typical externally guyed structures.

complicated the usual erection methods and tall structures made common guy anchors an impossibility or else greatly increased the tower stresses under transverse loading.

Guyed-V Tower. In 1957, the guyed V tower was developed⁹⁴ so that the guyed-mast principle would be more suitable for rough terrain; the guyed V consisted of the same two tripods moved laterally but was now held together by the crossarm.

Introduction of the guyed V helped promote the initial and serious use of helicopters for line construction for the first guyed-V towers, which were designed in aluminum. The very light weight of both the aluminum material and guyed-mast concept permitted transport and erection of a complete structure with the limited capacity of the helicopters then commercially available. Guyed-V tower use expanded rapidly with thousands of kilometers of lines built at up to the 500-kV level, fabricated in both steel and aluminum as the economies of the V principle were proving to be sufficient to justify use even when helicopter erection was not warranted.

Application expanded into the 750-kV class in the United States, Brazil, and Canada, and nominal spans were consistently in the 450- to 500-m range as the low cost of the extra height of taller towers (two masts and some guy wire) were extending the optimum envelope.

Single-mast guyed towers such as the delta were developed that offered compaction benefits and were also easy to use on rough terrain as they also require only one compression footing; the guy lengths are cut as required to fit the terrain. The guyed-V tower became the most widely used tower at the higher voltages, although all forms of guyed-mast structures were usually restricted to open terrain and areas where widespread guys were not considered to be hazards to the use of large farm equipment or where land occupancy was not a problem.

Cross-Rope Suspension (CRS) or Chainette. The next step in guyed-mast development followed from the failure of a 750-kV class tower due to material defect, a failure in a remote area where construction had been by a large mobile crane that could move only on the frozen winter roads. The replacement guyed-V structure was too heavy for available helicopter lift, and the repair was greatly delayed until crane access came with winter weather.

As voltages increase, all towers tend to become top-heavy, and the guyed-V or guyed-Δ are no exceptions. The urge to dispense with the crossarm led to the development of the *cross-rope suspension* (CRS) tower or *Chainette*, as it is referred to in Quebec, Canada.

The CRS concept was actually derived from the successful CRS system built in the mountains of British Columbia, Canada in 1955^{95,96} and uses one or more wire ropes suspended between two guyed masts to replace the crossarm and support the insulator strings. Even at 1000 kV, the individual masts are well within the capacity of modest low cost helicopters, and thus the problems of initial construction and emergency replacement are easily solved, with crane or helicopter. The initial

design of the CRS^{97,98} made use of the six-part suspension assembly because it was feared that galloping of a single phase might find the support point forces transferred through the rope system to the other phases and thus promote widespread and damaging activity. The CRS found application on the third, fourth, and fifth lines of the 735-kV James Bay system in Quebec and on a section of 500-kV lines in Oregon, in the United States.

The next applications and development have come about in South Africa at 400 kV and in the Argentine at 500 kV, where a single cross rope is used because of the absence of any significant icing and thus no fear of galloping.⁹⁶

All CRS lines must use a special construction or spacer rope extending between the tops of the masts; the initial use is to position the mast tops before the conductors are in place to provide tension to the system and subsequently to provide means of access to the phases by use of a wheeled ladder for both stringing and sagging work and for maintenance.

The CRS type of construction has a few negative aspects as it requires space at the tower sites (an open area that can be farmed), but the positive points are many. Both single- or multiple-rope CRS systems permit reduced phase spacing with increased SIL values and limited only by gradient effects or fear of wind clashing. On the 1150 km of the 500kV line in the Argentine studies showed that clashing were a negligible threat and the reduced phase spacings available by the CRS increased SIL values and reduced compensation costs by many millions of dollars. All wire rope components including

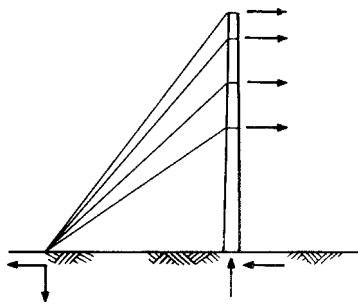


FIGURE 14-62 Single-shaft externally guyed structure.

the guys are precut to length and can be tested to working loads, and length adjustment is included in only one of the guys. The weight of structural steel in a tower will be about 50% of that of a comparable guyed-V or guyed-Δ tower. With overhead wires attached directly to the tops of the masts, the lightning protection is about as good as possible and the extra relaxation provided by the suspended wire assembly added to the insulator strings ensures that cascading potential is negligible.

Guying Rigid Structures. The guyed structures of the preceding section consisted of structural components pivoted or free to rotate at the connections to the foundations. Thus, the guy loads are in all cases determined by simple static analysis. The addition of guys to structures that are fixed or rigidly attached to the foundations (Fig. 14-62) produce arrangements that are indeterminate to varying degrees and

for some, the analysis of strength can be quite complex and performance will be dependent on introducing and maintaining precise levels of guy pretension.

The problems arise because of the large strains or stretch that guys develop in order to resist the loads and the varying degrees of rigidity of the structures that they are guying. Guyed-pole structures, as shown in Fig. 14-62, if they are wood and single-pole or the very common H-frame structure, are readily guyed, since the wood components are relatively flexible and allow the guys to develop load before the poles deflect enough to fail.

However, guyed-metal-pole structures that are fixed at their bases become more difficult to assess and analysis is usually needed to confirm both the distribution of loads between the guys and the poles themselves and also to set the pretension needed in the guys to ensure that the deflections or distortions of the components remain within limits. The design engineer must be conscious of the fact that deflections of poles can introduce large additional bending stresses caused by the P -Δ effect—the pole compression acting on the moment arm of the bow of the pole.

The most complex situation arises from attempts to guy rigid lattice structures (Fig. 14-63). In order to resist a load applied to the structure, the guys will normally stretch so much that the rigid structure will already have failed. Successful guying in such a manner requires either oversized guys to limit the stretch of the guys or very precise levels of pretension, set and maintained to distribute the loads in desired manner between the structure and the guys.

There is one condition under which guying of a rigidly framed structure is readily done and that is when the purpose is to restrict the movement of the structure on failure. Longitudinal

guying of rigid structures or even of H frames is a method of creating stop towers to limit the movement of slack and thus stop a cascading of structure if one is under way. Transverse guys are sometimes applied outside of heavy angle structures to restrict their failure mode and thus limit the amount of slack that can be introduced into the line system if the tower failure occurs under an extreme ice loading.

Foundation Types. A wide variety of foundation types can be used with self-supporting or guyed lattice, framed, and single-shaft structures. They include the following:

Lattice tower	Framed and single-shaft structures
Steel grillages	Concrete spread foundations
Concrete spread foundation	Drilled shafts
Rock foundation	Direct embedment
Drilled shafts	

Steel Grillages. Figure 14-64 shows three typical types of steel grillages. Figure 14-64a is a pyramid arrangement in which the leg stub is connected to four smaller stubs which in turn are connected to the grillage at the base. The advantage of this type of construction is that the pyramid can transfer the horizontal shear load down to the grillage base by truss action. However, the pyramid arrangement does not permit much flexibility for adjusting the assembly, if needed. In addition, it is difficult to compact the backfill inside the pyramid.

Figure 14-64b shows a grillage foundation which has the single leg stub carried directly to the grillage base. The horizontal shear is transferred through shear members that engage the passive lateral resistance of the adjacent compacted soil.

Figure 14-64c also has the single leg stub carried directly to the grillage base. This type of grillage foundation has a leg reinforcer which increases the area for mobilizing passive soil pressure as well as increasing the leg strength. The shear is transferred to the soil via the leg and reinforcer and resisted by passive soil pressure. The base grillage of these three typical foundations consists of steel beams, angles, or channels which transfer the compressive or uplift load to the soil.

The advantages of steel grillage foundations are that they can be purchased with the tower steel and concrete is not required at the site. The disadvantage is that these foundations usually must be designed before any soil borings are obtained and may have to be enlarged by pouring a concrete base around the grillage if actual soil conditions are not as good as those assumed in the original design. In addition, large grillages are difficult to set with required accuracy. The placement and compaction of the backfill material are critical to the actual load-carrying capacity and load-displacement characteristics of the foundation.

Concrete Spread Foundations. This type of foundation consists of a base mat and a square or round pier. It is constructed of reinforced concrete. There are several variations as indicated in Fig. 14-65. The stub angle can be bent and the pier and mat centered. The mat can be located so that the projection from the stub angle intersects the centroid of the mat or the pier itself can be battered to the tower leg slope.

The stub angle is embedded in the top of the pier so that the upper exposed section can be spliced directly to the main tower leg and diagonals. The stub angle should be of adequate size to resist the

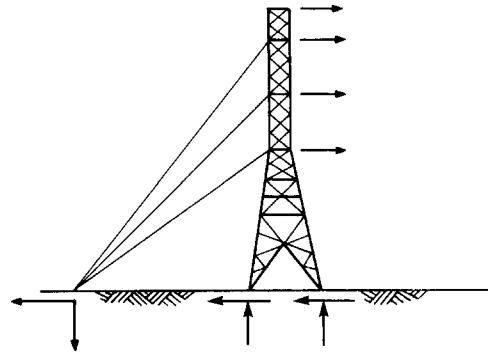


FIGURE 14-63 Externally guyed lattice tower.

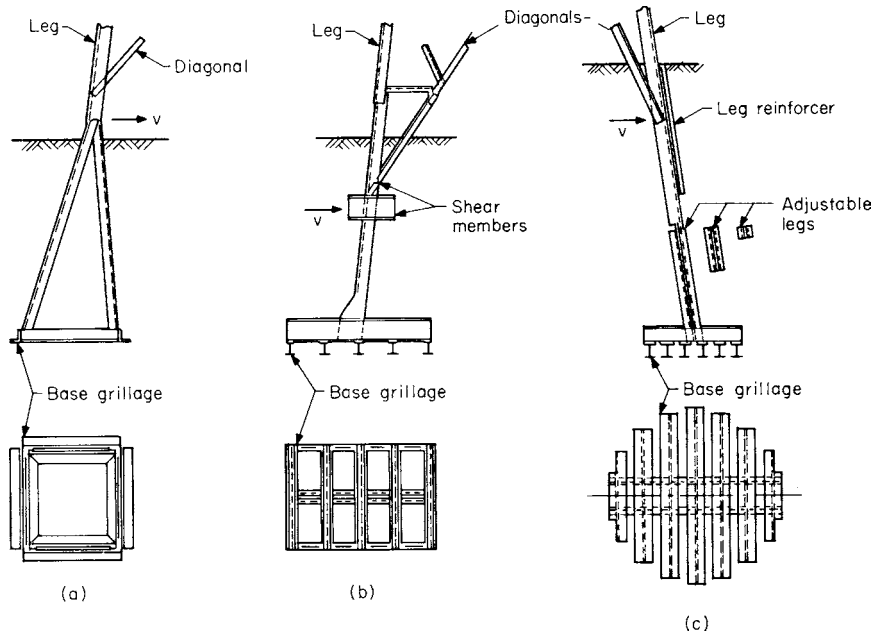


FIGURE 14-64 Typical steel grillage foundations.

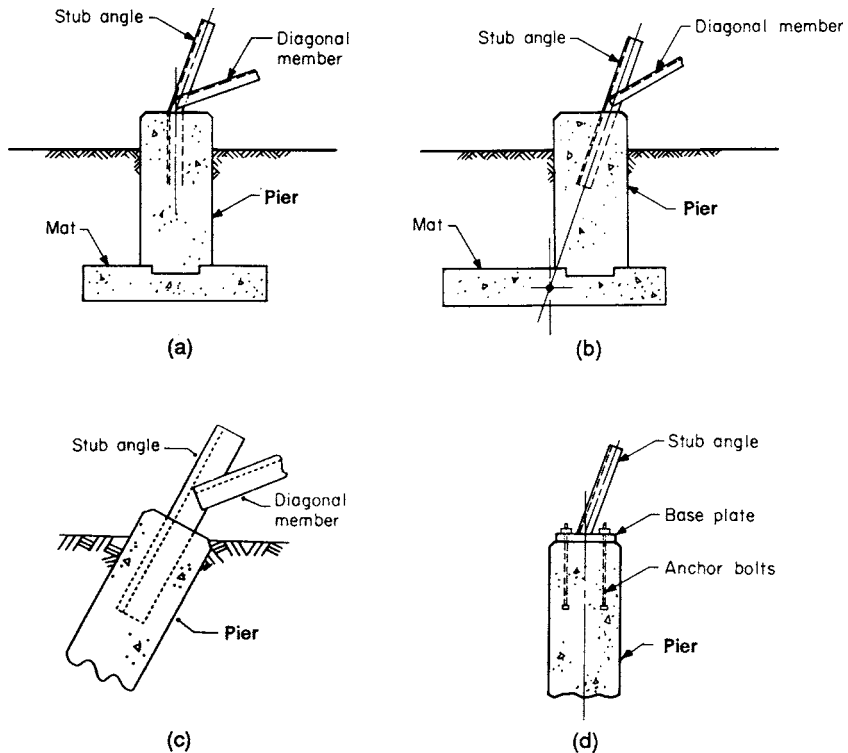


FIGURE 14-65 Typical concrete spread foundations (reinforcing not shown).

axial loads transmitted from the main leg and diagonals plus any secondary bending moment from the horizontal shear, if applicable. The stub angle must be embedded in the concrete to a sufficient length to transmit the load to the concrete. Bolted clip angles or welded stud shear connectors may be added to the lower end of the stub to reduce its length. Anchor bolts can also be used in lieu of the direct embedment stub angle as shown in Fig. 14-65d.

Rock Foundations. Many areas of the United States have bedrock either exposed at the ground surface or covered with a thin mantle of soil. Relatively simple, economical, and efficient rock foundations may be installed where this type of terrain is encountered. A rock foundation can be designed to resist both uplift and compression loads plus horizontal shear and, in some structure applications, bending moments. Where suitable bedrock is encountered at the surface or close to the surface, a rock foundation, as shown in Fig. 14-66, can be installed. Bolted clip angles or welded stud shear connectors may be added to the lower end of the stud to reduce its length.

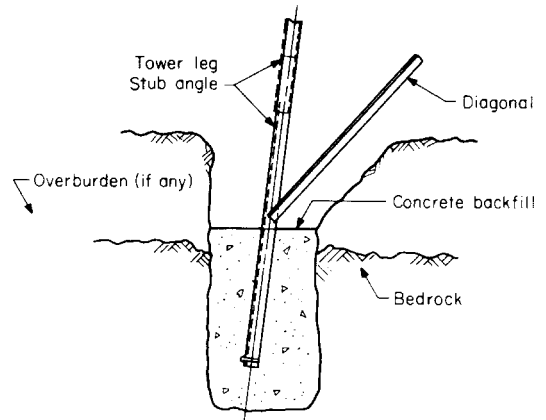


FIGURE 14-66 Rock foundations.

Drilled Shafts. The drilled concrete shaft is the most common type of foundation presently being used to support lattice towers, framed structures, and single shafts. Drilled concrete shafts are constructed by power augering a circular excavation, placing the reinforcing steel and pouring concrete to form a shaft foundation. Lattice towers are attached by embedment of a stub angle or through the use of baseplates and anchor bolts. Framed structures and single shafts are attached through the use of baseplates and anchor bolts.

Drilled shafts can be constructed in a wide variety of soil and rock types. However, the construction of drilled concrete shafts may encounter problems under certain soil conditions. For example, granular soils may collapse into the excavation before concrete can be poured. In soft, cohesive soils, squeezing or shear failure of the soil can occur, producing a reduced diameter or the excavation may become completely obstructed before the concrete is placed. This soil movement in the excavation can result in ground-surface settlement. Thus, casing and/or drilling mud may be required in granular and soft cohesive soils to maintain an open excavation.

Direct Embedment. Direct embedment refers to wood, steel, or concrete pole foundations (both single-shaft and H-framed structures) constructed by power augering a circular excavation in the ground, inserting the pole directly into the excavation, and backfilling the void between the pole and the sides of the excavation. Thus, the pole acts as its own foundation by transferring loads to the in situ soil via the backfill. This technique has been traditionally used for wood-pole foundations and has recently been employed for metal- and concrete-pole foundations.

The quality of backfill, method of placement, and degree of compaction strongly influence the stiffness and strength of a direct embedment foundation. Corrosion of an embedded metal pole is also an important consideration. It should be noted that the presence of granular or soft, cohesive soils may cause the same construction problems for direct embedment foundations as for drilled concrete-shaft foundations.

Subsurface Investigations. The technical requirement of assuring a safe and cost-effective foundation design for transmission structures requires a thorough knowledge of the subsurface conditions along the right-of-way (ROW). The intent of this section is to provide a guide for performing an adequate subsurface investigation for the design of transmission-line structure foundations.

When designing a foundation, the engineer should be concerned with the following factors: (1) the ultimate load-bearing capacity of the subsurface material, and (2) the allowable displacements of the foundation. In the case of grillages and directly embedded poles, the quality of available backfill materials is also a concern. Hence, the objectives of a subsurface investigation are to determine the stratigraphy, physical characteristics, and engineering properties (particularly the strength and deformation characteristics) of the soil or rock underlying a given site.

To determine the most cost-effective foundation, it is necessary to consider the engineering and physical properties of the subsurface materials; construction costs; the construction aspects of a particular foundation type and how they are influenced by such factors as groundwater elevation, safety requirements, contractor capability and experience, and environmental constraints.

The scope of a subsurface investigation will vary depending on foundation loads, type of structure, and probable foundation types, types of subsurface materials, and previous knowledge of subsurface conditions along the line route. It is necessary to use engineering judgment when considering the scope of the subsurface investigation. A detailed outline for developing a cost-effective investigation is given in an EPRI report.⁹⁹

Design of Spread Foundations. Spread foundations are used to support lattice towers. The design of spread foundations for transmission towers must consider both the direction (uplift or compression) and orientation (inclination and eccentricity) of the applied loads. The foundation must be designed to prevent excessive displacement or shear (bearing capacity or uplift) failure of the support soil. A detailed presentation of estimating the uplift and compression capacity of spread foundations is given in an EPRI report.⁹⁹

Design of Drilled Shaft Foundations. Drilled shaft foundations are used to support lattice-tower, framed, and single-shaft structures. This type of foundation supports vertical compression loads through a combination of side shear and end bearing and supports vertical uplift loads by side shear. Lateral loads and overturning moments are supported by lateral resistance of the soil and/or rock in which the shaft is embedded plus the vertical shearing resistance on the perimeter of the shaft, and the horizontal shear on the base and the base moment.

Compression and Uplift Capacity. Methods for computing the compression and uplift capacity of drilled shaft foundations are given in an EPRI report.¹⁰⁰

Lateral Load Capacity. The response of a drilled shaft to lateral loads is the result of complex interactions between the shaft and the soil and/or rock in which it is embedded. A common method of modeling this interaction is called the subgrade modulus approach. Reference 101 provides a detailed explanation of a method for determining the lateral capacity of drilled shafts. A computer program, MFAD (Moment Foundation Analysis and Design), originally called PADLL, which was developed as part of the EPRI research project eliminates the simplifying assumptions associated with prior models.

Direct Embedment. The response of direct embedment foundations in compression, uplift, and lateral loads is similar to that of drilled concrete shafts. Most of the analytical techniques used in drilled shaft design are relevant to direct embedment design. The principal differences between direct embedment foundations and drilled concrete shaft foundations are: (1) the backfill which intervenes between the pole and the in situ soil, and (2) the stiffness of the embedded structure shaft relative to that of a drilled concrete shaft. Drilled shafts transfer loads directly to the in situ soil. A detailed presentation for the analysis and design of directly embedded poles is given in an EPRI report.¹⁰² Results from 12 full-scale tests on single-pole direct embedment foundations are given in a related report.¹⁰³

Construction Considerations. Factors affecting, and problems associated with, the construction of drilled shaft foundations can be divided into two general areas: (1) geotechnical factors influencing construction, and (2) construction-related problems. A common geotechnical occurrence is the erosion (sloughing, caving in) of loose granular soil layers, mainly below the groundwater level. Another geotechnical factor influencing the overall capacity of the foundation is the release of stresses due to excavation, especially when the hole is left open for a long period of time (say, one or more

days, depending on soil conditions). Some construction-related problems are associated with the use of drilling mud (slurry method), which tends to leave an undesirable film (up to various inches of thickness) of soft material adhered to the walls of the hole. Another frequently occurring problem is the perturbation and remolding generated by the use of casing. Also, problems arise when special geometry is requested by the designer for the drilled shaft (under-ream, shear rings, etc.). In all of these cases, in general, good communication is required between field personnel and designers to permit early detection of these conditions.

Design of Anchors and Anchor Foundations. An anchor is a device which will provide resistance to an upward (tensile) force transferred to the anchor by a guy wire or structure leg member. An anchor may be a steel plate, wooden log, or concrete slab buried in the ground, a deformed bar or a steel cable grouted into a hole drilled into either soil or rock, or one of several manufactured anchors which are either drilled or rotated into the ground. Anchorage may also be provided by vertical or battered drilled shafts or piles. Typical types of anchors are shown in Fig. 14-67.

Anchors may be classified as either deadman or prestressed. Deadman anchors are defined as those anchors which are not loaded until the structure is loaded. Prestressed anchors are loaded to specified load levels during installation of the anchor. An advantage of a prestressed anchor is that most of the initial strains of the anchorage system have been removed before the structural load is applied. Therefore, the full capacity of the anchor can be attained at very small deformation (movements in soil of less than $\frac{1}{4}$ in are typical). Another advantage of prestressed anchors is that they are proof-loaded to their design load at the time of installation. Disadvantages of prestressed anchors are

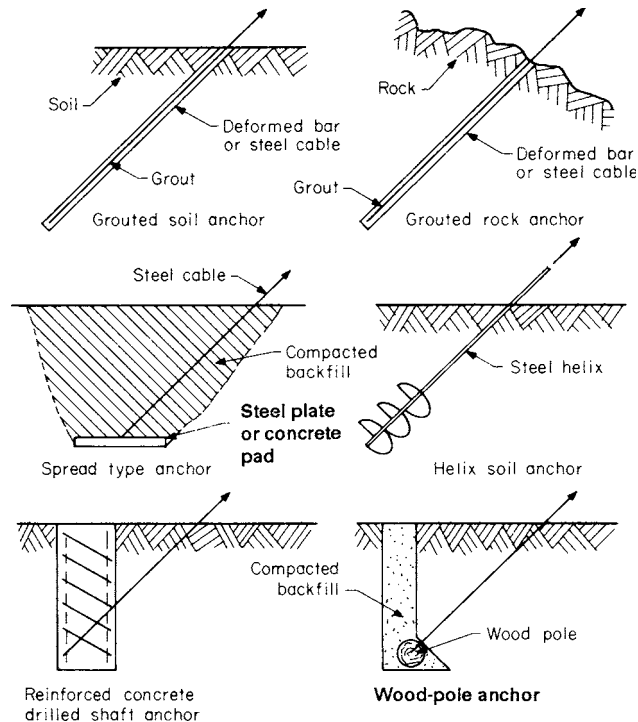


FIGURE 14-67 Typical anchors.

that they are generally more expensive than deadman anchors and they should not be used in compressible soils.

Another advantage of prestressed anchors is that shallow anchors may obtain additional strength by the increased effective stress created by the influence of the bearing plate on the soils adjacent to the anchors.

Deadman anchors may include any of the systems shown in Fig. 14-67. Initial strains in deadman anchors may be reduced by as much as 50% by prestressing them to their design load at the time of installation.

Anchor Application. Anchors are used to permanently support guyed structures, as well as to temporarily support other structure types during erection and stringing. The legs of lattice towers can be anchored directly by rock anchors or helix-type anchors. The uplift capacity of spread foundations may be increased through the use of anchors as shown in Fig. 14-68. Guys and anchors are also extensively used to terminate wire loads on wood structures and to increase wood structure capacity for high transverse loading. At intermediate structure locations, guys and anchors may be utilized to provide additional longitudinal strength. Anchors can be used to increase the load capacity of existing foundations.

Design. The design of an anchor depends on a knowledge of the peak and residual shear strength properties of the soil or rock in which it is embedded. In rock, it is also important to know the degree and depth of any weathering which may have occurred, together with the orientation and spacing of joints and foliation. In addition, an understanding of the load characteristics and the structure deflection tolerance combined with the guy cable elongation is important in selecting and designing the type of anchor. Anchor pullout tests are often conducted to confirm design assumptions where prior experience is lacking.

References 99, 104, and 105 provide detailed information on the design of anchors.

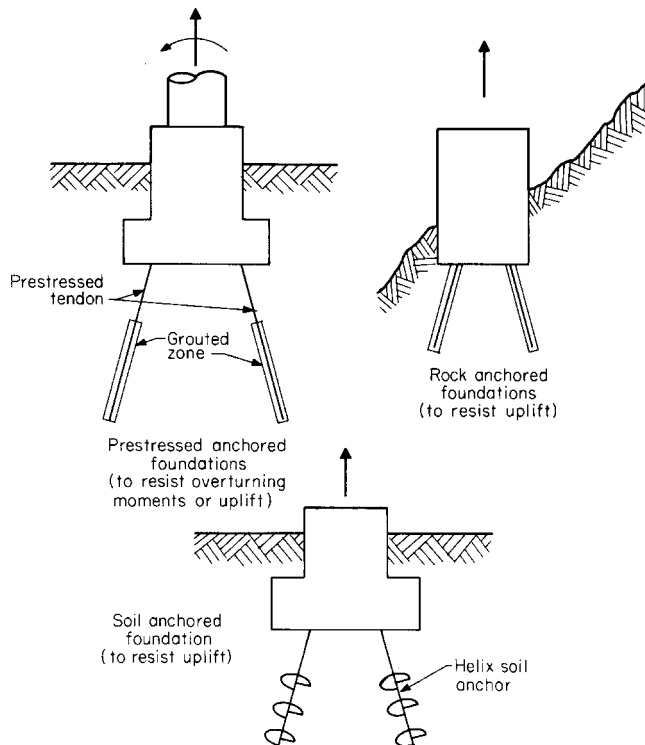


FIGURE 14-68 Typical anchored spread foundations.

14.1.15 Overhead Line Uprating and Upgrading

Performing a transmission line uprating can be very attractive in terms of getting smaller costs and shorter leadtimes when compared to building a new line. Besides that, it can postpone the need of new lines, reduce congestion costs and avoid unnecessary load shedding during contingencies. However, before starting the uprating task, it is important to evaluate some feasibility issues, as well as to choose the most appropriate type of uprating (Thermal Uprating or Voltage Uprating) for a specific transmission line. Each type of uprating requires different kinds of previous analysis and shall be done by its own methods. Sometimes a transmission line uprating also requires a line upgrading. Transmission line upgrading is related to physical modifications to the line.^{106,107}

Uprating Feasibility Issues

Technical Feasibility. For this kind of analysis it is important to consider at least the following points:

- *System load requirements.* It is important to evaluate for how long the uprated/upgraded line will satisfy the load requirements.
- *Assessment of current conditions and life expectancy of transmission line materials.* It is important to make this kind of evaluation for the main transmission line components, such as towers, foundations, conductors, insulators, and hardware.
- *Potential margins for uprating/upgrading.* It is important to check electrical clearances, mechanical strengths, ROW width, as well as the possibility of compliance with the requirements of safety codes (e.g., NESC), regulatory bodies and government agencies (e.g., navigable streams, public lands, air lanes).
- *Utility considerations.* Sometimes electric utilities are not authorized to take the transmission line out of service to perform the necessary uprate/upgrade services. In these cases it is important to check if the mentioned services can be done with the line in service.

Economical/Financial Feasibility. For this kind of analysis it is important to consider at least the following points:

- *Uprating/upgrading costs vs. new line costs.* It is important to remember that technical analysis of old lines usually requires data gathering and this can be very expensive and time consuming. Besides that, it is necessary to estimate what will be the need of the uprated line in terms of additional ROW. Other costs that can be relevant are related to construction (material and labor), maintenance and operation of the uprated line. Environmental costs are usually higher for new lines.
- *Uprating/upgrading costs vs. uprating/upgrading benefits.*

Environmental Feasibility. For this kind of analysis it is important to consider at least the following points:

- *Environmental considerations.* Usually not so critical when compared to new lines. However, it may be necessary to deal with historical societies, environmental groups, concerned neighbors, and so forth.
- *Right-of-way easements.* If significant changes will be made to the original line, it is necessary to check the validity of the previous ROW terms of use. It can be difficult to get licensing for the modified line. It is also important to check the existence of ROW encroachments and line crossings that would be unacceptable by the uprated line.

Thermal Uprating

Effectiveness. This kind of uprating can be a good option when the line loading is limited by thermal constraints and the line has margin in terms of maximum allowable conductor temperature.

Previous Analysis to Perform. Before proceeding with a transmission line thermal uprating it is necessary to analyze maximum allowable conductor temperature, conductor-to-ground clearance, magnetic fields, ROW issues, and sometimes structural strengths.

Usual Techniques. Some of the techniques used to perform transmission line thermal uprating are described as follows:

- Performing dynamic thermal rating monitoring
- Raising the thermal limit imposed to the line by some inexpensive substation equipment (e.g., disconnect switches)
- Raising the thermal limit by making similar the thermal limits of all line sections
- Keeping appropriate conductor-to-ground clearances while increasing the maximum allowable conductor temperature
- Bundling the original line conductor with another one, or replacing the line conductor by a more conductive one, to increase the line current-carrying capacity

Some of these techniques have large structural impacts. Performing a transmission line thermal uprating can bring some impact to the substation equipment.

Voltage Uprating. This kind of transmission line uprating can result in a much higher rating increase than thermal uprating. Besides that, transferring the same amount of power in a higher voltage level reduces the line current, and consequently, line losses and voltage drops. However, voltage uprating is typically more expensive than thermal uprating due to the need of also uprating the voltage class of the terminal substations equipment.

Effectiveness. This kind of uprating can be a good option when: the line loading is limited by voltage drop or stability considerations; the line has margins in terms of electrical clearances; the uprating can be done with minimal line modifications or it will be applied to several circuits simultaneously, or the line design criteria can be relaxed.

Previous Analysis to Perform. Before proceeding with a transmission line voltage uprating it is necessary to analyze tower clearances, conductor-to-ground clearance, corona performance, electric fields, ROW issues, and sometimes structural strengths.

Some Usual Voltage Uprating Techniques. Some of the techniques used to perform transmission line voltage uprating are described as follows:

- Addition of insulator units to the transmission line insulator strings
- Replacement of standard insulator units by polymeric or antifog units
- Application of strut insulators (or V strings) to prevent swinging of suspension strings
- Keeping appropriate conductor-to-ground clearances while increasing the transmission line operating voltage
 - Retensioning the existing conductors
 - Performing sag adjustments (cutting out conductor lengths, sliding conductor clamps)
 - Increasing the conductor height at the attachment support (converting suspension strings to pseudo dead-end strings)
 - Increasing the attachment support height
 - Raising towers
 - Moving towers
 - Inserting additional towers
 - Performing terrain contouring (rural areas)
- Bundling the original line conductor with another one, or replacing the line conductor by a bigger one, to assure a good corona performance
- Performing Line Compaction
- Converting a 3-phase double-circuit line to a 6-phase single-circuit line
- Converting a low voltage double-circuit line to a high-voltage single-circuit line
- Converting HVAC lines to HVDC lines

Some of these techniques have large structural impacts.

Voltage Upgrading of Existing Lines.

Figure 14-69 illustrates the fact that as transmission voltages increased over the years experience and research has allowed smaller conductor spacings in per unit of the spacing required to withstand power frequency voltage flashover. An observation from Fig. 14-69 is that many lines designed years ago may have clearances sufficient for operation at a higher voltage than the initial operating voltage of the line. Thus, possibilities exist for upgrading the voltage of some older existing transmission lines.

A voltage upgrading study involves reengineering the line using the best available data. Upgrading differs from new line design because operating experience with the existing line provides a source of data not available to the designer of a new line.

It also differs from new line design in that certain reduced design margins may be accepted in order to avoid a complete replacement of structures and conductors.

Voltage upgrading of transmission line ranges from increasing the voltage with minimal modifications to virtual reconstruction of the line. The greater the extent of the modifications, the more mechanical and structural issues become significant. An important part of an upgrading study is careful verification of the existing condition of the line, including conductors, insulators, geometry, structures, and foundations.

Insulation concerns are paramount in a voltage upgrading analysis but trade-offs are frequently necessary between competing requirements. For example, it may not be possible to add insulators of the same type as the original while maintaining the same leakage distance per kilowatt and without adversely impinging on air gap clearances. In such cases several options may be considered, including relaxation of the initial design criteria.

Insulation for power frequency voltage is concerned with contamination performance of insulators and air gaps between energized and grounded line components. An advantage of an upgrading study is the availability of operating experience of the existing line. It is important to carefully review the operating performance of the line at the existing voltage, because problems that may have been previously ignored may become significant with the increased electrical stress at the higher voltage.

Insulator leakage distance required is a function of the degree of insulator contamination at the location of the line. The degree of contamination maybe well known, or if necessary can be determined by laboratory tests. An insulator string can be carefully removed from the existing line so as not to disturb the surface dirt and sent to a laboratory for testing in a fog chamber, or alternatively a sample of the contamination can be taken from insulators on the line and the equivalent salt deposit density determined.

Once the degree of contamination is understood, several options can be considered if there is insufficient space to add conventional insulator units to the strings:

- *Use less leakage distance per kilowatt.* It may be determined that adequate performance can be obtained with less leakage distance than would be customarily be applied to a new line design.
- *Different insulator types.* Additional leakage distance may be possible by application of high leakage or fog-type insulators without excessively lengthening the insulator string length. The hydrophobic properties of polymer insulators may be considered for reducing the leakage distance. Porcelain insulators with semiconducting glaze provide improved contamination performance and may be an option.

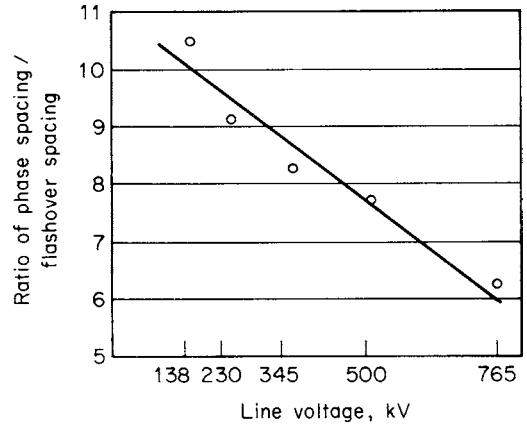


FIGURE 14-69 Phase-spacing ratio versus line voltage.

Adequate air gap clearances must be maintained under maximum wind swing conditions. Because power frequency voltage is always present, it is necessary to consider insulator swing for the maximum predicted wind speed to maintain adequate clearance for power frequency voltage withstand. It is also necessary to maintain adequate clearances to the edge of the ROW to meet code requirements.

Switching surges have typically not been an issue for the lower transmission voltages. However, in a voltage upgrading, it is necessary to utilize the available space to the maximum degree possible and switching surges can become the dominant effect in limiting voltages. Therefore, a careful switching surge analysis is an important part of a voltage upgrading study. Some transmission lines have been successfully upgraded with proper control of switching surge overvoltages. Control methods may be necessary even at 115 kV and include:

- Use of resistor preinsertion in the circuit breakers
- Application of surge arresters
- Synchronized pole closing circuit breakers

Code and maintenance issues are part of a voltage upgrading study. Control of switching surge overvoltages may allow operation of the line at the new voltage with the same ground clearance that existed previously. The old line may have been designed in compliance with older code editions that are based on a linear relationship between clearance and voltage. Control of switching surge overvoltages may allow use of the alternate clearance calculation and reduced clearances compared to the linear calculation. Likewise, switching surge overvoltages are part of the safety considerations for live line working.

If it is necessary to increase conductor ground clearance to maintain code clearances, retensioning of the conductors may be a possible way of meeting the code requirements. Retensioning conductors increases mechanical forces on dead end and heavy angle structures and necessitates analysis of structure loading. Code ground clearances may also relate to the allowable length of insulator strings. Structures may be modified to increase conductor height. Once structure modifications are considered, structure and foundation loadings must be carefully studied.

Lightning tripout performance is seldom a limiting consideration for a voltage upgrading study. Lengthening the insulator string increases the insulator impulse CFO. Increased voltage adds to the lightning impulse voltage half the time and subtracts half the time depending on the instant of the lightning strike in relation to the power frequency voltage sine wave. The degree of change of line geometry depends on the amount of structural modifications necessary. A lightning performance calculation program can be used to compare the performance before and after the upgrading. Comparison of the calculated performance of the existing line with the line operating record calibrates the program to the line and allows estimation of the change in performance to be expected with the upgrading. Normally the change will be slight. If it is desired to improve the lightning performance with the upgrading, methods such as reducing the structure footing resistance are available.

Corona on energized conductors, hardware, and insulators is a fundamental limitation on the maximum possible voltage on any transmission line. As the voltage is increased, the electric field at the surface of energized components increases. At some point the electric field becomes sufficient to ionize the air and produce excessive corona. Corona manifests itself as electromagnetic interference (EMI—radio noise and television interference), audible noise, and in more extreme cases visible corona and corona power loss. An analysis of corona effects is an essential part of a voltage upgrading study.

Audible noise traditionally has only been a concern for the higher transmission voltages, for example, 500 kV and above. Because corona effects are often the limiting factor for a voltage upgrade, the conductor surface electric field on an upgraded line can be at levels typical of EHV lines, even for 115 kV. Thus, audible noise can become an issue for upgraded lines at voltages where audible noise has traditionally not been a consideration. In any event, it may be necessary to demonstrate adequate audible noise performance to obtain authorization for the upgrade.

Conductor corona caused EMI is the quantity predicted by radio and television noise programs and is the value traditionally used for evaluation of new transmission line designs. The assumption is made that if noise from conductor corona is at an acceptable level, noise from other sources will be insignificant. If EMI limits the voltage below the desired new voltage, mitigation options are

reconductoring or adding a second conductor per phase. The second conductor per phase may be added in either a horizontal or vertical configuration. The vertical configuration may be preferred if it impinges less on the air gap clearances to the structure under wind swinging than the horizontal configuration. Reconductoring or adding a second conductor per phase requires a mechanical and structural analysis to ensure the conductors can be properly supported.

While conductor corona EMI is also an essential consideration for voltage upgrading, additional noise sources such as corona on hardware and insulators may become important. "Corona-free" hardware has been used for EHV lines where the electric field on the hardware is greater, while standard hardware has been used for lower voltage lines. The difference for bolted conductor shoes is that standard hardware has the U-bolts arranged so the nuts are on the underside of the shoe, while for corona-free shoes the U-bolts are inverted so the nuts are inside the shoe where they are electrically shielded. Because the electric field on the hardware of an upgraded line may be at levels typically associated with EHV lines, it becomes necessary to change the hardware to corona-free hardware to avoid excessive radio noise.

Under some conditions it may be desired to test hardware or insulators to ensure adequate corona performance. If laboratory tests are performed, care must be taken to properly reproduce the expected electric field at the surface of the hardware or insulators. Traditional laboratory tests have used a voltage above the desired operating voltage and measurement of radio influence voltage (RIV). These tests have been adequate for traditionally designed lines, but may give misleading results for compact or upgraded lines where the surface electric fields are greater than traditional values for the voltage level. Therefore it is necessary to properly characterize the electric field on the device under test.

Experience has indicated that when a transmission line is properly designed for corona-caused EMI, more than 90% to 95% of radio noise complaints and virtually all television interference complaints are a result of spark sources. These spark sources are located and repaired by normal maintenance techniques. Such spark sources include such things as loose bolts or down lead staples on wood poles or films of corrosion between caps and pins of adjacent units in slack strings of suspension insulators. Noise complaint experience for the line considered for upgrading and the physical condition of the line are valuable indicators of the possible presence of spark noise sources. Increasing the line voltage will increase the possibility of spark noise sources and should be considered as part of a voltage upgrading study.

Upgrading voltage might be considered for a line remote from population where audible and EMI noise are deemed of secondary importance. In such a case the possibility of upgrading may be limited by visible corona and corona loss. At some point, as the voltage is increased the power loss in foul weather becomes excessive and increase of voltage becomes impractical.

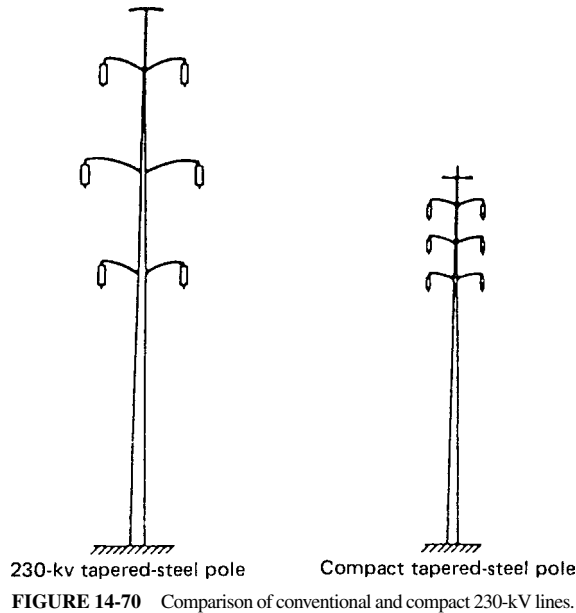
Voltage upgrading studies are frequently performed in two parts: a preliminary analysis to determine if voltage upgrading of the desired line is feasible, followed by a detailed analysis if the feasibility analysis proves promising. Typical or approximated data may be used to assess feasibility. The scope of the detailed analysis is set by the feasibility study. Not all voltage upgrading studies include all of the same elements. Laboratory tests may be included, in some cases, even construction of a prototype line section for testing. In other cases, some aspects of the detailed study may be of smaller importance because of the degree of margin in the existing design.

Compact Line Design. The most fruitful areas for line compaction are 69- to 230-kV lines, because these designs are generally older, with more generous clearances. Figure 14-70 illustrates a comparison of compact and conventional 230-kV structures. Some compaction is possible, however, at higher transmission voltages by redesign, as shown in Fig. 14-71.

Compact line design techniques may be applied for more efficient use of ROW for new construction, voltage uprating of existing lower-voltage lines, and possible economies. Line compaction is also a tool for reducing electric and magnetic fields at ground level.

A compact transmission-line design analysis consists of the following topics:

Conductor Surface Electric Field and Corona. A given conductor in air has a maximum surface electric field for acceptable levels of corona. EHV lines are typically designed for conductor surface electric fields near this maximum. Compaction of lower-voltage lines raises the conductor surface electric field to EHV levels. Thus conductor and phase spacing/configuration must take corona



phenomena into account: corona loss, radio noise, and audible noise. Audible noise is not a normal consideration for lower transmission voltages, but should be analyzed for compact lines because of the field levels involved. Because the conductor surface electric field of a compact line is at EHV levels, it is necessary to use EHV-class hardware to limit hardware corona. Laboratory test procedures must be specified in terms of electric field on the conductor surface rather than system voltage.

Insulation Performance. Power frequency voltage (including insulator contamination), switching surge, and lightning performance must be evaluated for the proposed design. Switching surge control can be provided either by surge arresters or resistor preinsertion in the circuit breakers.

Conductor Motion. The one consideration in design of a compact high-voltage transmission line which differs from EHV practice is mechanical motion of the conductors under wind, ice, and through-fault currents. It is imperative that conductor motion be limited to maintain adequate clearances for power frequency voltage. Differential wind motion, conductor motion under ice release, and ice galloping are extensions of existing practice. A new consideration is motion which results from *through-fault current* (fault current which flows on a line due to a fault somewhere else on the system). Especially with horizontal conductor configurations, magnetic forces from through faults can develop enough conductor motion to cause a line trip.

Because of the need to restrict conductor motion, compact lines are customarily designed with post insulators to restrict conductor motion at the structures. If necessary, inspan insulating spacers can be applied to restrict the conductor motion. Maximum compaction (minimum conductor spacing) is achieved by designs which eliminate grounded supporting structure members in the space between conductors. The spacing reduction is a result of the need for clearances for phase-to-phase voltage between conductors rather than twice the phase-to-ground clearance. Portal structure designs support the conductors from outside the conductor array and are useful for line compaction.

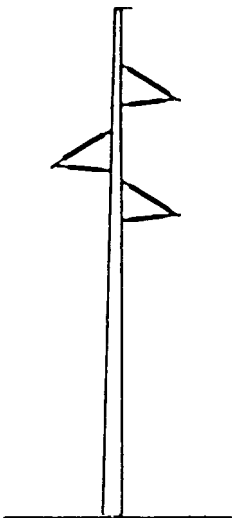


FIGURE 14-71 A 500-kV compact line.

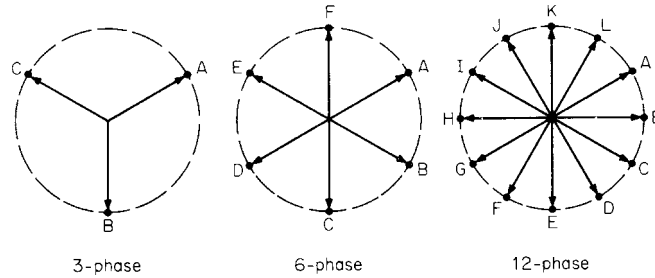


FIGURE 14-72 Illustration of high-phase-order phasor diagrams.

A limitation of compact line design may be a restriction on live-line maintenance because of the reduced clearances. If live-line maintenance is considered in the design phase, it may be possible to develop procedures and to modify the design to allow live-line work while meeting applicable safety codes.¹⁰⁸

High-Phase-Order Transmission.^{109–112} This is an extension of the principles of line compaction to more than three phases. A general principle can be developed for maximum power transfer in a given amount of space with a given amount of conductor material. The result of this development is that the conductors should be spread symmetrically around the periphery, and energized with the highest possible voltages and phase angles corresponding to the space angle between conductors. The conductor and phase configuration is illustrated for 6- and 12-phase in Fig. 14-72.¹¹¹ High-phase-order lines can be constructed smaller than 3-phase lines for equivalent capacity.

An alternative way of looking at high phase order is that conversion of a double-circuit 3-phase line to 6-phase at the same phase-to-ground voltage reduces the conductor surface electric field. This reduced conductor surface electric field can be used either to bring the conductors closer together (compaction) or to increase the phase-to-ground voltage. Thermal loading increases linearly with voltage, and surge impedance loading increases with the square of the voltage. As a result, high phase order holds the potential for voltage uprating of existing double-circuit 3-phase lines by conversion to 6-phase at a higher phase-to-ground voltage.

The benefits and practicality of high phase order have been proved by 3 years' successful operation of a demonstration 6-phase line near Binghamton, New York. An existing double-circuit 115-kV line was converted to 93-kV 6-phase, for a 40% increase in phase-to-ground voltage. A section was converted to compact design, and relay protection was developed and tested. Substation layout proved practical, and economic results are favorable for appropriate applications.^{114–118}

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14.2 UNDERGROUND POWER TRANSMISSION

By E. C. BASCOM, III and J. A. WILLIAMS

14.2.1 Cable Applications

Traditionally, underground cable systems have been installed in major urban areas where overhead lines are not practical—locations such as airport approaches because of safety issues or water crossings. Cables are generally much more costly than overhead lines from the standpoint of material and installation costs, although recent trends regarding rights-of-way and permitting costs often make the underground alternative more competitive. Increasingly, cables are being selected because existing rights-of-way are too congested or unavailable, or local municipalities will not tolerate a new overhead transmission line. Transmission cables may also be applied for substation getaways, crossings under major overhead line corridors, directionally drilled installations and other installations where technical considerations favor underground cables. Utilities sometimes find it prudent to place short dips in critical areas of overhead circuits, to allow installing overhead lines, which would not otherwise be permitted.¹

Extruded dielectric (XD)—principally cross-linked polyethylene (XLPE)—cables have become the U.S. standard for voltages up to 230 kV, with short installations up to 345 kV. Over the last 7–8 years, XLPE cables have been used worldwide at 400 and 500 kV. High-pressure fluid-filled pipe-type cables are less commonly installed because of concerns about the dielectric liquids and higher maintenance, but there are a few thousand circuit miles that continue to operate, and several new circuits are installed annually. New self-contained liquid-filled (SCLF) cable installations are being displaced by the availability of XLPE cables at higher voltages. Mass-impregnated nondraining (MIND) paper cables are used for high voltage direct current (HVDC) circuits, although one manufacturer has started supplying polymeric-insulated cable for dc applications. Compressed-gas-insulated transmission systems are uncommon for new installations and used only for special applications—typically short lengths and high-power transfers within substations. In the United States, even though most new installations are extruded dielectric, pipe-type cables account for about 70% of the approximately 6000 circuit miles (10,000 km) in service; XD accounts for 25%, and self-contained liquid-filled accounts for the remainder—with a very small amount of compressed-gas-insulated cables.

14.2.2 Cable System Considerations and Types

Cable Integration into Utility System. Planning and operating considerations for underground cables are different from those for overhead lines.² Special attention should be paid to properly represent the cables for utility system analyses, capacitance effects including charging currents, reactor application, system restoration, inductance effects including load sharing, surge impedance loading, insulation coordination, system insulation requirements, and losses. As cables are used at higher voltages—230 kV and above—charging current and reactive compensation should be carefully evaluated. In addition to the effect of cable capacitance on system operation, the current required to charge the capacitor reduces the allowable cable rating. Charging current can be determined from Eq. 14-89, which shows that the charging current increases proportionally with voltage.

$$I_{\text{Charging}} = 2\pi f C E_0 = \frac{2\pi f \epsilon E_0}{18 \ln \frac{D_{\text{INSULATION}}}{D_{\text{CONDUCTOR}}}} \times 10^{-9} \quad (14-89)$$

In Eq. 14-89, f is the power frequency, C is the capacitance, ϵ is the insulation dielectric constant (specific inductive capacitance), and E_0 is the line-to-ground voltage in volts.

Table 14.24 lists several characteristics of overhead lines and underground cables.³ Cables tend to “hog” load compared to overhead lines because of the lower surge impedance as compared to

TABLE 14-24 Typical Electrical Characteristics, 230-kV Overhead Line and Underground Cables

Parameter	Overhead Line	Underground XLPE	Underground HPFF (PPP)
Shunt capacitance, $\mu\text{f}/\text{F}/\text{mi}$	0.015	0.30	0.61
Series inductance, mH/mi	2.0	0.95	0.59
Series reactance, ohm/mi	0.77	0.36	0.22
Charging current, A/mi	1.4	15.2	30.3
Dielectric loss, kW/mi	0+	0.2	2.9
Reactive charging power, MVA/mi	0.3	6.1	12.1
Capacitive energy kJ/mi	0.26	2.3	7.6
Surge impedance, ohms	375	26.8	14.6
Surge impedance loading limit, MW	141	1975	3623

overhead lines, although they generally have a lower thermal rating than comparable overhead lines. Since cable ratings are usually lower, potential load flow problems should be investigated when integrating long cable lines in parallel with overhead lines.

14.2.3 Extruded-Dielectric Systems

Extruded-dielectric systems sometimes called solid-dielectric cables provide a simpler, often lower-cost alternative to the paper-insulated cables that have historically been used for transmission cables. Extruded-dielectric cable types have included linear low-density polyethylene (LLDPE), cross-linked polyethylene (XLPE), and ethylene-propylene-rubber (EPR), although XLPE is now the most common insulation type used for transmission cables particularly since the challenges of manufacturing EHV cables with XLPE insulation have been addressed. The absence of dielectric fluid greatly simplifies the ancillary equipment and accessory complexity, and removes concerns about fluid leaks. The XD cables also have lower capacitance than paper-insulated cables, simplifying their integration into the utility system. Although the first XD cables were installed in the United States in the 1960s, they did not find extensive use until the mid 1980s.

Extruded-dielectric cables consist of a copper or aluminum conductor, a conductor semi-conducting shield to ensure a smooth electrical profile in the insulation, an extruded polymeric insulation, an extruded insulation shield, outer metallic shielding, and typically a moisture barrier such as a lead sheath or metallic foil laminate, covered with a polymeric (usually polyethylene) jacket (Fig 14-73).

The “true triple extrusion” method is the state-of-the art method for applying the semi-conducting shields and insulation in one pass through the extrusion line to provide sound, void-free interfaces, especially with transmission cables. Extruded-dielectric cable insulation is extremely sensitive to the presence of partial discharge; consequently, this cable must operate under ionization-free conditions.



FIGURE 14-73 345-kV extruded-dielectric cables. (Courtesy of LS Cable.)

Exacting manufacturing standards supported by an effective quality assurance system and extensive factory testing are all necessary to provide a high-quality product suitable for application at the highest transmission voltages.

Contrary to initial industry expectations, XD insulation has proven to be sensitive to moisture so transmission cables use moisture barriers to prevent ingress into the insulation. Water blocking is sometimes used on stranded conductors, and water-swellable textile tapes or powder are applied under the metallic sheath. Early cables were steam cured, but most high-voltage extruded-dielectric cables manufactured since the mid-1990s are dry-cured and many are dry cooled (CDCC, continuous dry curing and cooling). Moisture-barrier conductors and swellable tapes under the sheath help maintain the cable free from moisture, particularly when the cable sustains mechanical damage such as from a dig-in. Great improvements in the cables and their accessories in the last decade have led the U.S. utilities to conclude that extruded-dielectric cable reliability is now comparable to paper cables.

Sheath bonding is an important design consideration and requires more careful consideration than at distribution voltage levels. If both ends of the sheath are grounded as is common in distribution, conductor current induces currents in the sheaths, causing heat losses that derate the cable by 10–35%. If the sheath is grounded at one point, the heat losses from circulating currents are eliminated but sheath voltages are induced, equal to approximately 150 V/1000 A/km. Cross bonding, electrically transposing the sheaths, can eliminate sheath circulating currents (although eddy currents still remain) while maintaining acceptable induced voltages.⁴

Extruded-dielectric cables are typically installed individually, either directly buried or in duct. In some cases, the three individual phases are installed at one time in a plastic or steel pipe as part of a “trenchless” installation, in a manner resembling a pipe-type cable installation. Splice spacing ranges from 300 to 1000 m, depending upon the installation mode, reel-shipping lengths, and allowable sheath voltages.

Taped, taped- and field-molded, prefabricated, and premolded splices (Fig. 14-74) have been used; although, premolded splices (joints) are used almost exclusively today.

Terminations have either porcelain or polymer housings, and most designs have a small amount of dielectric liquid (e.g., silicone oil) or gas (SF_6) in the termination.



FIGURE 14-74 “Click-fit” premolded joint. (Courtesy of Prysmian.)

14.2.4 High-Pressure Fluid-Filled (HPFF) Systems

Pipe-type cable had been the U.S. standard because of its ruggedness, and the relative ease of installing pipe in city streets. The first pipe-type cable was a 66-kV circuit installed in Philadelphia in 1932. Many hundreds of miles of 230- and 345-kV pipe-type cables were installed in the 1960s and 1970s. Its use was declined in the late 1980s, as more extruded-dielectric cables were installed and as heavy voltage cable usage generally diminished.

A welded, coated, cathodically protected steel pipe, typically 8.625 or 10.75 in optical density, is pressure and vacuum tested, and the three mass impregnated cables are pulled together into the pipe (Fig 14-75). The cables consist of a copper (occasionally aluminum) conductor, conductor shield, taped insulation, insulation shield, outer shielding, and skid wire to prevent cable damage as they are pulled into the pipe. High-quality kraft paper is typically used at 138 kV and sometimes 230 kV. Introduction of a laminated paper—polypropylene—sometimes referred to as PPP for paper-polypropylene-paper—insulation in the 1980s permitted a lower insulation thickness (0.600 in at 345 kV versus 0.920 in for kraft paper), with lower electrical losses, so this type of insulation is now selected for most new 230 kV and all 345 kV circuits.

Splices are typically spaced at 2000–3500 ft intervals. Terminations with porcelain housings make the transition to air insulation and atmospheric pressure.

For a high-pressure liquid-filled (HPLF) system, which has been proven experimentally up to 765 kV though never commercially applied above 345 kV in the United States, the pipe is pressurized to approximately 200 psig (1.4 MPa) with dielectric liquid to suppress ionization. Expansion and contraction of the liquid requires large reservoir tanks and sophisticated pressurizing systems. This provides the possibility of removing the fluid periodically along the length of the line, cooling it (called “forced cooling”), and returning it to the pipe to obtain a 20–50% ampacity increase. Pipe-type cables offer several opportunities for uprating because of the presence of the dielectric liquid.

Nitrogen gas at 200 psig (1.4 MPa) may be used to pressurize the cable at voltages to 138 kV. This high-pressure gas-filled (HPGF) system requires a slightly greater cable insulation thickness because of the poorer insulating qualities of the gas. However, the system greatly reduces environmental concerns because there is limited free dielectric liquid if there is a leak in the pipe, and no external pressurizing equipment is required other than a regulator, nitrogen cylinder, and alarms.



FIGURE 14-75 Pipe-type cable.

14.2.5 Self-Contained Liquid-Filled (SCLF) Systems

This system was developed in the 1920s, and was a worldwide standard outside the United States through the 1980s. There are many miles in operation at 525 kV, for both land and submarine cables. The cable conductors have a hollow core that provides a longitudinal feeding path for the dielectric liquid. A low-pressure design requires less than 10 psig (70 kPa) pressure to suppress ionization, while a medium-pressure design typically operates at 50–75 psig (350–515 kPa). The 525-kV cables at Grand Coulee dam have a reinforced sheath; the lower end of these cables operates at 400 psig (2.8 MPa).⁵

The cables are maintained gas free at a positive pressure from manufacturing through energization and operation because the lower operating pressure (than pipe type) would allow gas ionization, if present. The liquid volume is much lower than that for an HPFF cable. Fluid expansion and contraction is accommodated by bellows-type expansion tanks distributed along the route at spacings



FIGURE 14-76 Self-contained cable.
(Courtesy of Prysmian.)

that depend upon sheath construction, core diameter, type of liquid, temperatures, circuit topography, and power transfer. Special fluid stop joints are installed to divide the cable route into a number of hydraulic sections as required because of static pressures (due to route profile) or dynamic pressures (due to fluid volume changes during heating and cooling transients). For very long circuits such as submarine cables, an active pressurizing plant is employed, resembling the plant used for fluid-filled pipe-type cables.

Figure 14-76 shows a self-contained cable. The conductor is most commonly copper, although aluminum has been used. Conductor shields, insulation, and insulation shields are similar to those for pipe-type cables. A lead, reinforced lead, or aluminum sheath maintains pressure, excludes moisture, and provides a fault current path, although submarine cable circuits often include additional copper to support return currents. Aluminum sheaths are usually corrugated to improve flexibility. A polymeric jacket isolates the sheath from ground and provides mechanical and corrosion protection.

Self-contained cables are especially suited for long-distance water crossings because they can be produced in long splice-free lengths, which minimize—or in some cases, eliminate—the number of field splices. Wire armor is

provided to aid in cable installation and retrieval, and give a small measure of mechanical protection.

14.2.6 Direct Current Cables

DC cables are used for long water crossings and their shore ends. Charging current and dielectric losses make ac cables unsuitable for lines more than 30–50 mi long (50–80 km), depending upon voltage level and insulation type. Traditional HVDC cables used a mass-impregnated solid-type cable impregnated with a very high-viscosity fluid that had no active fluid pressurizing system (Fig. 14-77). This cable is used for very long (>25 mi, >40km) dc submarine applications. Self-contained liquid-filled or pressurized gas-filled cables have been used for the shorter lengths. Table 14-25 provides a listing of major dc installations. Polymeric insulation materials have recently been developed that are suitable for dc applications, usually combined with IGBT (voltage source) valve converters instead of thyristor valves; these types of HVDC cables can feed smaller loads not connected to large ac systems as was traditionally required.

The insulation for dc cables is especially critical since the insulation is resistively graded instead of capacitively graded as with ac systems. The electrical stress distribution in a dc cable is a function of insulation temperature—electrical stresses can be higher at the outer shielding, whereas for ac cables, the stress is always highest at the conductor shielding. Mass-impregnated cables are generally limited to 50°C-conductor temperatures to avoid temperature distributions that would give too high a stress at the outer shielding.

14.2.7 Gas-Insulated Transmission Lines (GIL)

These “cable” types consist of sulfur hexafluoride (SF_6) gas or a mixtures of SF_6 and nitrogen at pressures from 30–45 psig (200–315kPa) serving as an insulation between a coaxially spaced tubular aluminum conductor and tubular aluminum shield. Insulating spacers maintain separations as shown in Fig. 14-78.

The system is supplied in rigid 40-ft lengths. Large diameters are required because the gas is a poorer insulator than paper-insulated or extruded-dielectric cables—the first 345-kV system had an

18-in enclosure diameter for each of the individual phases. The large diameter enhances heat transfer, conductor sizes are large, and the SF₆ insulation does not have the thermal limitations that other cable types have. Ampacities are therefore very high, usually able to match overhead line capacities with one conductor per phase so these cables often are employed to make high-capacity bus connections within substations. The system is especially suited for short distances, very high currents, and extra-high voltages—the first system was a 600-ft, 2000 A, 345-kV installation.⁶

14.2.8 Superconducting Cables

Superconducting wire has existed for several decades, taking advantage of liquid helium (4 K) temperatures (“low temperature” superconductors) to cool various materials to the point that they show no appreciable electrical resistance. Within the last 5 years, “high temperature” superconductors (HTS) using liquid nitrogen temperatures (80 K) were developed along with methods to make the wire in length suitably long to apply to cables. Two basic types of HTS cable exist; one is the “cold-dielectric” type (Fig. 14-79) where the insulation is at cryogenic temperatures, while the other is a warm dielectric where only the conductor is operating at cold temperatures.

High-temperature superconductors-cable technology offers advantages since the HTS-cable system operates independent of the thermal environment in which it is installed while allowing significant power transfer—using high current densities—with single circuits potentially matching the capacity of overhead lines. HTS cables also offer the possibility of transferring bulk power at what have traditionally been medium voltages by taking advantage of the high current density capability rather than stepping up the voltage as is typically done with conventional “transmission” circuits. One possible application is to retrofit an HTS cable into existing cable pipes or conduits to provide for a significant power transfer increase without the high associated costs of construction and obtaining rights-of-way.

While there has been aggressive research to apply HTS cables at transmission voltages, they have seen only limited use in commercial power systems. Long-term reliability of the cryogenic cooling plants has not been proven, and accessories—joints and terminations—require further development. Cost is also a significant factor in making these systems commercially viable. Materials and installation costs for HTS cable systems are close to 20 times that of a conventional power cable system. Even at this price point, there are certain applications—usually where construction costs, permitting or obtaining rights-of-way are impractical—that HTS cables could see some use. The technology is expected to improve with new generations of superconducting wire becoming available and improved reliability of accessories and cooling plants.

14.2.9 Cable Capacity Ratings: Ampacity

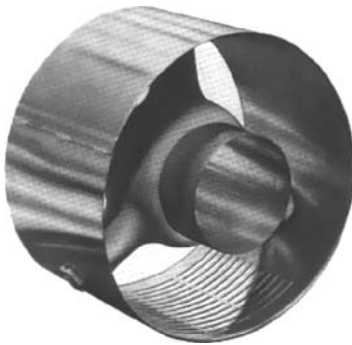
The ampacity (current rating) for underground cables is limited by the maximum conductor temperature that can occur in the insulation with rated current flow through the conductor. The insulation material that is in contact with the conductor shield limits the maximum conductor temperature.



FIGURE 14-77 HVDC mass-impregnated cable. (Courtesy of Prysmian.)

TABLE 14-25 DC Cable Installations

Name of Link	Date	Voltage (kV)	Power (MW)	Length (km)	Cable Type
Gotland 1	1954	100	20	100	MI
Cross Channel 1	1961	100	80	2 × 52	MI
SACOI	1965	200	100	2 × 118	MI
Cook Straight 1	1965	250	300	64	PIGF
Konti-Skan 1	1965	285	300	64	MI
Vancouver 1	1969	300	156	3 × 27	MI
Mallorca/Menorca	1972	200	100	3 × 44	SCFF
Skagerrak 1,2	1976	263	250	2 × 125	MI
Vancouver 2	1976	300	185	2 × 35	MI
Hokkaido/Honshu	1980	250	150	2 × 42	SCFF
Gotland 2,3	1983	150	160	2 × 100	MI
Cross Channel 2	1986	270	250	8 × 50	MI
Konti-Skan 2,3	1988	285	300	2 × 64	MI
Fenno-Skan	1989	400	500	200	MI
Cook Strait 2	1991	350	500	3 × 40	MI
Skagerrak 3	1993	350	500	125	MI
Cheju (Korea)	1993	180	150	2 × 96	MI
Baltic	1994	450	600	250	MI
Morocco-Spain	1995	300	600	26	SCFF
Kontek (Germany)	1995	400	600	170	MI
Gotland	1999	+/-80	65	2 × 70	Polymer
Kii Channel	1999	500		4 × 50	SCFF
Sweden-Poland	2000	450	600	235	MI
Moyle (NIE)	2000	250	500	2 × 55	MI
Italy-Greece	2001	400	500	200	MI
DirectLink	2001	+/-80	180	6 × 59	Polymer
Norway-Germany	2001	500	600	578	MI
MurrayLink (Australia)	2002	+/-150	200	2 × 180	Polymer
Cross Sound	2002	+/-150	330	2 × 40	Polymer

**FIGURE 14-78** GITL spacer. (Courtesy of CGIT Westboro.)

The conductor temperature is determined by the heat generated within the cable—electrical losses (I^2R) and dielectric losses (ac cables only)—which passes radially to ambient earth through various thermal resistance layers in the cable, duct (when present), trench, and surrounding soil. The temperature of the conductor can be determined from the following thermal equivalent circuit (this circuit is shown for XD or superconducting final focus [SCFF] cables).

Ampacity can be calculated for XD, SCFF, and HPFF cables by solving the equivalent thermal circuit for conductor temperature based on the type of cable being considered. Figure 14-80 shows an equivalent thermal circuit for an extruded transmission cable installed in conduits. The earth thermal resistance depicted in Fig. 14-80 includes the concrete envelope or other special backfill, if present. Equation 14-90 for the XD cable modeled in Fig. 14-80 is:

$$\begin{aligned}
 T_{\text{Conductor}} = T_{\text{Ambient}} + W_{\text{Dielectric}} \times & \left(\frac{R_{\text{Insulation}}}{2} + \overline{R_{\text{Jacket}}} + \overline{R_{\text{Jacket-to-Duct}}} + \overline{R_{\text{Duct}}} + \overline{R_{\text{Earth}}} \right) \\
 & + I^2 R_{\text{Conductor}} \times \left(\overline{R_{\text{Insulation}}} + Qs(\overline{R_{\text{Jacket}}} + \overline{R_{\text{Jacket-to-Duct}}} + \overline{R_{\text{Duct}}} + \overline{R_{\text{Earth}}}) \right)
 \end{aligned}
 \quad (14-90)$$

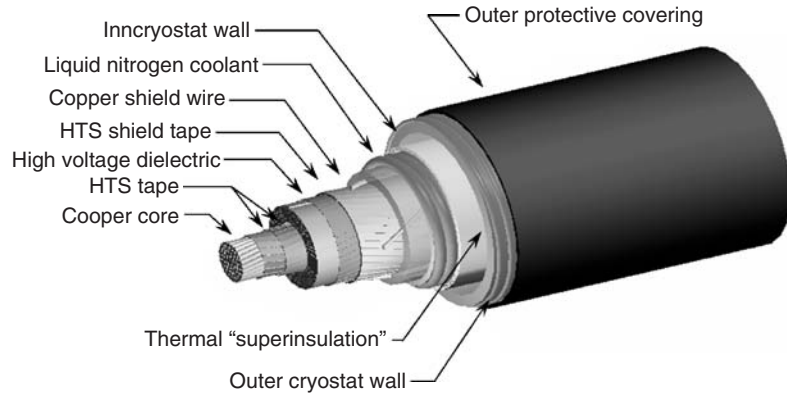


FIGURE 14-79 Cold dielectric HTS superconducting cable. (Courtesy of American Superconductor.)

where the various variables are noted as in Fig. 14-80 with Q_s being the ratio of losses from the conductor and sheath to the losses only in the conductor.

The earth thermal resistance portion of the equivalent thermal circuit is defined by Eq. 14-91:

$$\begin{aligned} \overline{R_{earth}} = & \frac{\overline{\rho_{backfill}}}{2\pi} \cdot n \cdot \left(\ln\left(\frac{D_x}{D_{earth}}\right) + LF \cdot \ln\left(\frac{2 \cdot L + \sqrt{4 \cdot L^2 - D_{earth}^2}}{D_x}\right) \right) \\ & + \frac{\overline{\rho_{backfill}}}{2\pi} \cdot n \cdot LF \cdot \ln(F) + \frac{\overline{\rho_{native}} - \overline{\rho_{backfill}}}{2\pi} \cdot n \cdot N \cdot LF \cdot G_b \end{aligned} \quad (14-91)$$

where $\overline{\rho_{backfill}}$ is the thermal resistivity of the backfill in °C-m/W, D_x is the diameter beyond which the average (rather than peak) daily losses are experienced, D_{earth} is the outer diameter of the cable, pipe or conduit, n is the number of cables within that earth diameter, L is the burial depth to the center of the backfill, LF is the daily loss factor (ratio of peak losses to average losses), F is a mutual heating effect factor for $N-1$ cables or pipes with N being the number of cables/pipes/conduits installed, $\overline{\rho_{native}}$ is the native soil thermal resistivity in °C-m/W and G_b is a geometric factor for the backfill envelope.

For ampacity calculations, the dielectric heating is assumed to be constant since the voltage level is generally held to be constant. Also, we can calculate the temperature rise from ac heating as

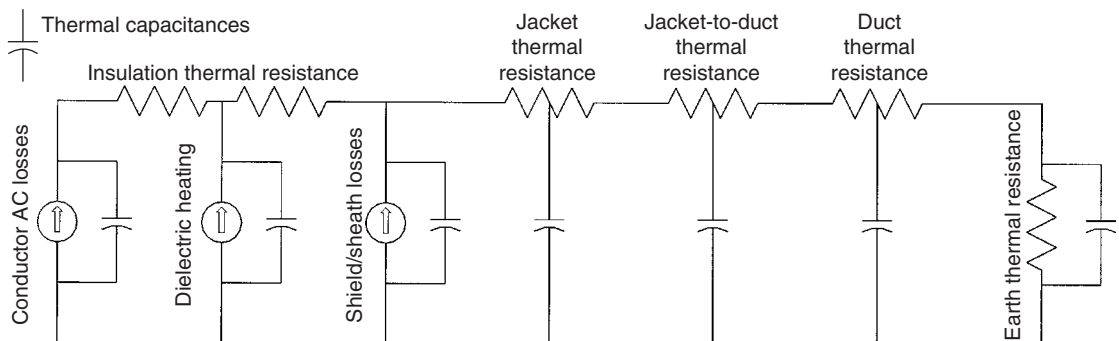


FIGURE 14-80 Equivalent thermal circuit for XD cable installed in conduit.

$I^2 \times (\Sigma R_{AC} \times \overline{R_{Thermal}})$. Then the conductor temperature can be found as $T_{conductor} = T_{Ambient} + \frac{\Delta T_{Dielectric} + I^2 R_{AC} \times \overline{R_{Thermal}}}{\Sigma R_{AC} \times \overline{R_{Thermal}}}$ from which the current for a given conductor temperature can be found:

$$I = \sqrt{\frac{T_{Conductor} - \Delta T_{Dielectric} - T_{Ambient}}{\Sigma R_{AC} \times \overline{R_{Thermal}}}} \quad (14-92)$$

A detailed procedure for calculating ampacity is beyond the scope of this reference. The reader is referred to Refs. 7 and 8 for additional information. The main elements that make up the thermal circuit include the following:

Conductor resistance, is determined based on the cross-sectional area of the conductor, the conductor material (copper or aluminum), the maximum operating temperature, the ac skin, and proximity effects. The maximum operating temperature is defined by the insulation material. Industry-accepted limits for the maximum conductor temperature are 85°C for paper or laminated paper-polypropylene insulations, 75°C for high-density polyethylene insulation, and 90°C for cross-linked polyethylene or ethylene-propylene-rubber insulations. Following the Association of Edison Illuminating Companies (AEIC) practices, these maximum temperatures are reduced by 10°C when the earth thermal parameters are not well defined.

Insulation thermal resistance is expressed in K-m/W (1 K temperature rise occurs when 1 W of heat flows through a thermal resistance of 1 K-m/W). The thermal resistance of the insulation or any cylindrical layer of cable material (i.e., jacket, pipe coating, and conduit) with an inner diameter D_i , outer diameter D_o , and material thermal resistivity of $\bar{\rho}$ can be found as follows:

$$\overline{R_{insulation}} = \frac{\bar{\rho}}{2\pi} \ln\left(\frac{D_o}{D_i}\right) \quad (14-93)$$

Typical values for various cable materials are shown in Table 14-26.

Dielectric loss is the heat generated in ac cable insulation as a function of diameters, voltage, insulation temperature (indirectly, as a function of temperature-dependent dissipation factor), specific inductive capacitance, and dissipation factor. Reference 7 should be used to calculate dielectric losses.

Shield/sheath losses are conductor current-dependent losses that result from induced circulating and eddy currents in the cable shield and sheath. Their value depends strongly on the sheath bonding method as described in Sec. 14.2.2.

Earth thermal resistance depends on the cable burial depth, cable phase spacing, cable diameter, native soil thermal resistivity and special backfill thermal resistivity. For a single cable buried in the soil, the thermal resistance can be found from Eq. 14-94:

$$\overline{R_{earth}} = \frac{\overline{\rho_{earth}}}{2\pi} \ln\left(\frac{2L + \sqrt{4L^2 - D_e^2}}{D_e}\right) \quad (14-94)$$

L is the burial depth to the center of the cable, and D_e is the diameter to the outside of the cable (for direct buried cables) or the outside diameter of the conduit (for cables in conduit). Transmission circuits generally have one cable for each of the three phases, and some installations

TABLE 14-26 Typical Values for Various Cable Materials

Material	Thermal Resistivity, $\bar{\rho}$ K-m/W
High-density polyethylene (HDPE)	3.5–4.0
Cross-linked polyethylene (XLPE)	3.5
Ethylene propylene rubber (EPR)	4.0–5.5
Oil/paper/laminated paper-polypropylene	5.0–6.0
Polyvinyl chloride (PVC)	4.0–7.0

TABLE 14-27 Typical Values of Soil Thermal Resistivities

Material	Thermal Resistivity, $\bar{\rho}$ K-m/W
Fluidized Thermal Backfill (FTB)	0.40–0.75
Concrete	0.30–0.80
Stone screenings	0.40–1.00
Thermal sand	0.50–1.00
Uniform sand	0.70–2.00
Clay	1.00–2.50
Soil with high-organic content	2.00–4.00

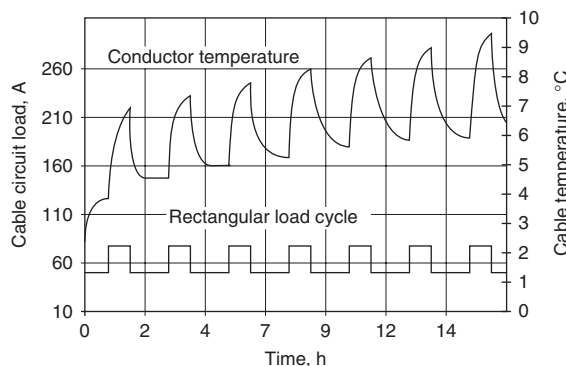
include multiple circuits within the same trench. To account for mutual heating that can occur, an additional term must be included in the total earth thermal resistance, as follows:

$$\overline{R}_{mutual} = \frac{\overline{\rho}_{earth}}{2\pi} \ln \left(\frac{d_{i1}'}{d_{i1}} \cdot \frac{d_{i2}'}{d_{i2}} \cdot \dots \cdot \frac{d_{in}'}{d_{in}} \right) \quad (14-95)$$

where d_{in}' is the distance from cable i to the image of cable n , and d_{in} is the actual distance from cable i to n . For a single 3-phase circuit, $n = 2$. For a double 3-phase circuit (6 cables), $n = 5$. The hottest cable should be used as cable 1.

The soil thermal resistivity varies from 0.5 to 4.0 K°-m/W and is dependent on moisture content, material, mixture, size of particles, and degree of compaction. The earth thermal resistance accounts for up to 75% of the total thermal resistance from conductor to ambient. Although it is not possible to control the native soil thermal resistivity, it is common to backfill the cable trench with special low-resistivity materials such as thermal sand or Fluidized Thermal Backfill (FTB). Most extruded and self-contained liquid-filled systems in duct are encased in a high-strength concrete envelope for mechanical protection and to promote heat transfer. Reference 8 describes the way to model the thermal resistance of this envelope of material. Typical values of soil thermal resistivities are listed in Table 14-27.

Thermal capacitances shown in the thermal circuit are important for calculating the temperature response to load cycle changes or emergency ampacity capability. References ⁹ and ¹⁰ discuss the thermal capacitances of cables in detail. When load changes occur on an underground cable circuit, the temperature of the conductor does not respond instantaneously. A simplified load shape—rectangular load pattern—applied to a previously unloaded extruded-dielectric cable circuit is shown in Fig. 14-81. Note that the hourly fluctuations in the load pattern are in close correlation with the temperature response; these changes reflect the relatively short thermal time constant—a few

**FIGURE 14-81** Temperature response to step load shape.

hours—for cable components. In contrast, the overall average temperature is rising as the duration of the applied load increases; this reflects the relatively long thermal time constant of the earth—approximately 50–150 h—for the mass of soil around the cables.

The impact of the earth thermal capacitance is routinely included in ampacity calculations by using a daily (24 h) “loss factor.” The loss factor is essentially the load factor of the losses and is the ratio of the peak losses to the average losses over a day according to Eqs. 14-96 and 14-97. Beyond a certain diameter out in the earth, the average effects of heat loss, rather than the peak losses, are experienced. So, the thermal resistances are adjusted accordingly to consider this effect. As the loss factor drops, the ampacity increases. The loss factor concept was initially developed in the Neher-McGrath paper in October, 1957 and is used by many utilities, particularly in North America. International practice (IEC-60287) has been used to calculate ampacities with 100% loss factor (flat load shape), which is generally very conservative since most cable circuits experience at least some load cycling over a 24-h period. Advanced numerical techniques have been applied on a limited basis to consider longer load cycles (several days to several weeks), but the ability to predict load over such long periods limits their applicability.

The mechanics of calculating ampacity are not particularly difficult, but there are many details to be considered. All of the calculations can be done using a hand calculator but are amenable to straightforward computer programming or a computer spread sheet. Ratings for many standard configurations are tabulated in Ref.¹¹.

High-Pressure Fluid-Filled Cables. Ampacity for HPFF cables may be calculated in a similar manner as for single-core cables. The main difference is that there is an additional element—the cable pipe—that generates heat in the equivalent thermal circuit. The pipe itself heats, and the magnetic pipe causes additional ac losses in the cables. A subtle difference for HPFF cables is that the heat generated by three cables—the three cable phases—must pass through the dielectric fluid in the cable pipe, the pipe coating, and the earth.

Compressed-Gas-Insulated Systems. Heat loss from GITL is by convection and radiation through the air since these systems are almost exclusively installed in air; usually open air but sometimes in enclosed troughs or tunnels. Consequentially, the rating procedure is significantly different from buried cable systems where heat loss is by conduction through the soil. The procedure for calculating ratings is generally an iterative process needed to evaluate the fourth-order relationships—guessing a temperature and rating and then comparing the calculated radiation and convection heat loss to the ohmic (I^2R) heat generated by the bus.

$$W_{\text{radiation}} = 5.69 \times 10^{-8} (T_2^4 - T_1^4) \pi D \left(\frac{1}{\frac{1}{\epsilon} + \frac{1}{\epsilon} - 1} \right) \quad (14-96)$$

$$W_{\text{convection}} = 8.523 \pi D \sqrt{\frac{(T_2 - T_1)^4}{\frac{T_2 - T_1}{2}}} \quad (14-97)$$

With T_2 and T_1 representing the temperature of the GITL surface and ambient air, respectively, D representing the outer diameter of the emitting surface, $e = [1 - D/(6\pi d)]^2$, and ϵ representing the emissivity of the emitting surface. Details of the calculations can be found in Refs. 12 and 13. For the situation where the GITL is exposed to solar radiation, the methodology used to model solar radiation on overhead transmission lines can be applied.^{7, 14, 15}

Transient and Emergency Ratings. Emergency ampacity considers the use of a higher operating temperature for a period combined with the heat storage capacity of the cable and earth environment. The temperature response of a single cable to a given heat output, W , can be found from Eq. 14-98:

$$\theta_{\text{Earth}}(t) = W_{\text{Cable}} \frac{\bar{P}_s}{4\pi} \left[-Ei \left(-\frac{D_{\text{earth}}^2}{16\delta t} \right) + Ei \left(-\frac{L^2}{\delta t} \right) \right] \quad (14-98)$$

TABLE 14-28 Acceptable Operating Temperature Values

Material	Maximum Temperature (Normal), °C	Maximum Temperature (Emergency), °C
High-density polyethylene (HDPE)	75	90 (<1500 h over cable life)
Cross-linked polyethylene (XLPE)	90	105–130 (<72h)
Ethylene propylene rubber (EPR)	90	130 (<1500 h over cable life)
(Oil/paper/laminated paper Polypropylene	85	100 (<300 h)–105 (<100 h)

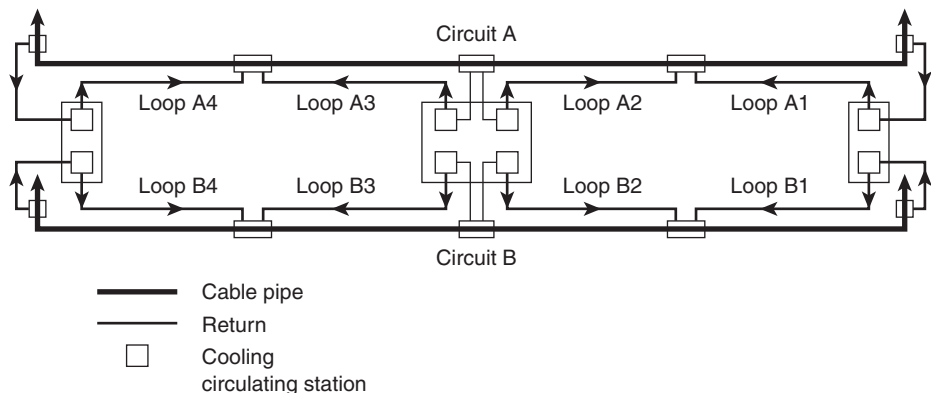
In compliance with AEIC specifications, these temperatures must be reduced by 10°C if the thermal environment is not defined for the entire circuit. A thermal route survey, ideally done prior to cable installation, eliminates this requirement. Dielectric fluid circulation in HPFF cables will also help mitigate the effects of localized conditions.

where δ is the earth thermal diffusivity in mm^2/h t is the time of the transient in seconds, L is the burial depth to the center of the cable, conduit, or pipe D_{earth} is the diameter of the cable/conduit/pipe-to-earth interface and ρ_s (needs “overline”) is the thermal resistivity of the soil in $\text{K}^2\text{-m/W}$ and Ei is a notation to indicate an exponential integral. Further details for calculating emergency ratings may be found in Refs. 10 and 16.

Transient ratings are those in which the heat-storage capacity of the cable system permits short-duration overcurrents without exceeding allowable temperatures. The maximum allowable temperatures and permissible emergency rating durations are defined by cable specifications and agreement with manufacturers. Generally, acceptable operating temperature values are listed in Table 14-28.

A detailed procedure for calculating emergency ratings is available in Refs. 9 and 10.

Forced Cooling. Forced cooling is not very common and is generally considered only for HPFF cables where the dielectric liquid in the steel pipe can be circulated. There are some limited applications where water is circulated through parallel water pipes to provide forced cooling of extruded or self-contained cables. In HPFF cable systems, the dielectric liquid can be removed from the pipe, cooled by various types of heat exchangers, and reintroduced into the pipe at a remote location, generally using a noncabled liquid supply pipe (note that the heat capacity of nitrogen is small so HPGF lines are not forced cooled). The procedure can increase the capacity of the cable circuit by providing a lower-resistance path for the heat generated in the cable to escape to ambient. Figure 14-82 illustrates a typical hydraulic circuit for a forced-cooled cable.

**FIGURE 14-82** Hydraulic circuit, typical forced-cooled HPFF cable system.

The major additional components of a forced-cooled HPFF system include a return pipe for the fluid, heat exchangers, circulating pump (800–1600 L/min), lower-viscosity dielectric fluid, and modifications to the cable pipe to prevent cable damage from impinging oil. Reference 17 describes a typical 345 kV forced-cooled system, Ref. 18 describes a procedure for making thermal calculations, and Ref. 19 describes full thermal and hydraulic calculation procedures for pipe-type cables.

The added cost and complexity of forced-cooling equipment, along with potentially high-energy charges for operation of the equipment, have tended to limit forced-cooled installation to areas of very high-installation costs, or to retrofitting on existing HPFF cable lines.

Self-contained and extruded cables can be forced-cooled¹⁸ using parallel water pipes (lateral cooling), conduit water circulation (integral cooling), heat pipes, or internal (core) cooling (Fig. 14-83). One North American utility uses parallel water-cooling pipes to increase the ampacity of a submarine cable as it comes on shore; the shore zone for submarine cables is often limiting, so the cooling system mitigates the ampacity limitation.

Internal cooling for self-contained liquid-filled cables has the advantage of removing dielectric fluid with high heat content from the core of the cable itself. This system requires special joints to periodically remove the line-potential liquid, pass it through heat exchangers, and return it to the cable core.

Lateral and integral cooling have a somewhat lower efficiency, but the simplicity of the cooling system has lead to several commercial installations. Extruded-dielectric cables can make use of either integral or lateral cooling. It is also possible to cool CGIT in the same manner, although there have been no such installations to date.

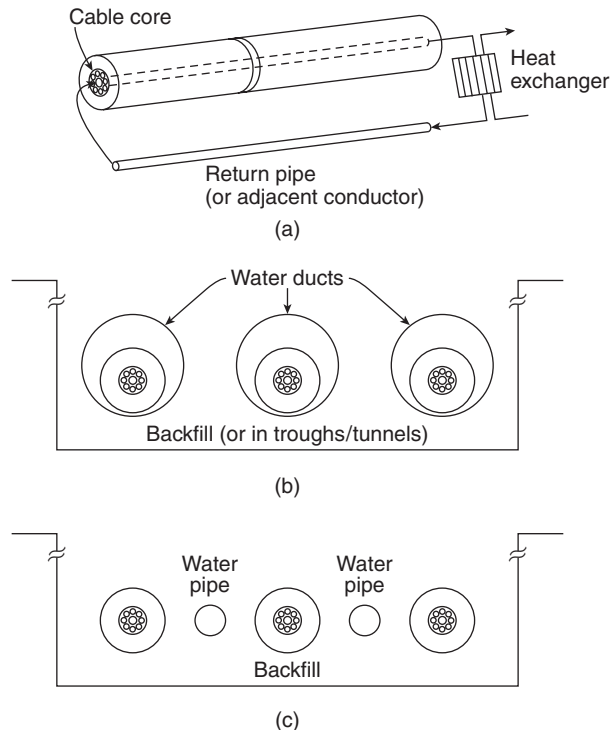


FIGURE 14-83 Alternate methods of cooling single-core cables: (a) internal (core) cooling (SCFF only); (b) integral cooling; (c) lateral cooling.

14.2.10 Cable Uprating and Dynamic Ratings

Cable uprating and upgrading are techniques that are applied to existing cable circuits to get more power through existing infrastructure without building new lines. Many of the basic strategies used for uprating are important to consider for basic ampacity when a new circuit is installed. Utilities frequently need to “uprate” existing circuits; an uprating project can often be implemented quickly to achieve a 10% increase in rating while deferring a multimillion dollar new installation project for several years. In addition, rights-of-way are sometimes difficult to obtain even for underground circuits so getting more capacity through existing lines becomes critically important. Underground cables are especially amenable to uprating, principally because of the very large thermal time constant of the cable/earth system. Also, many older circuits were designed and rated using conservative assumptions; these assumptions may be reviewed carefully, often revealing additional circuit capacity.

Utilities have successfully implemented many approaches for uprating.²⁰ Typical uprating approaches are summarized below:

- *Characterize the thermal circuit.* In most cases, design engineers properly make conservative assumptions when rating the circuit. A careful audit of route as-built drawings, soil and backfill thermal resistivity, load shape, and so on will provide accurate data and can often permit rerating the circuit 5–10% higher.
- *Perform thermal analysis.* Thermocouples or fiber-optic distributed temperature monitoring cables (Fig. 14-84) can tell the actual cable or pipe temperature at discrete locations or continually along the route. Detailed analysis of loading for the preceding weeks, cable construction data, and trench cross-section information can permit refining the ampacity model, often resulting in significant ampacity increases.²¹
- *Mitigate hot spots.* The thermal analysis may indicate hot spots—a few meters of cable that limit the overall circuit rating—along the route. If the hot spots are localized, they can perhaps be mitigated by



FIGURE 14-84 Distributed temperature system and fiber being used in the field to measure cable temperatures.

removing excess overburden, replacing poor soil with good backfill, recompact the soil or injecting an additive to reduce thermal resistivity. Sometimes transmission circuits can be upgraded by rerouting nearby distribution circuits or inserting heat pipes to cancel mutual heating effects. Dielectric fluid circulation in HPFF cables can also mitigate localized hot spots.²² Pipe circuits with only one pipe (no parallel circuit or separate fluid return pipe) can also have some modest circulation using the large fluid reservoir tanks to oscillate fluid in the pipe, mitigating hot spots.

- *Take advantage of load shapes.* Because of its long thermal time constant, the temperature of a cable system today is a result of its loading history for the last several weeks. Utilities typically choose a conservative daily load factor when performing ampacity calculations. Careful calculation of the effects of the actual hourly loads can result in increased ampacities.
- *Fill ducts with a slurry.* The static air space in an XD or SCFF cable duct reduces ampacity by 5–6% or more as compared to a similar direct buried cable. Filling the duct with a removable slurry such as a sand-bentonite mixture can restore that ampacity. Duct ends must be sealed to prevent drying, and it still may be necessary to water jet the slurry if the cable must be removed later. Care must be taken to avoid air pockets, especially if there are dips in the route profile.
- *Reconductor.* Technically called “upgrading,” substantial ampacity increases can be achieved for pipe-type cables or XD/SCFF cables in duct by removing the present cable and installing a larger conductor cable, possibly using lower loss insulation (e.g., PPP instead of conventional kraft paper). Utilities sometimes consider allowing a thinner insulation wall on the replacement cable to allow additional space in conduits or pipes for a larger conductor size. Cables with a higher voltage might also be installed, providing a power transfer increase directly proportional with the voltage increase, but this is seldom economical unless the higher voltage already exists in the terminal substations.
- *Add forced cooling.* For HPFF cables, it is possible to remove the liquid from the cable pipe, pass it through a heat exchanger, and send it back into the pipe through a separate liquid line. Although installation and operating costs are high, forced cooling can add 40% to the capacity of an existing cable system. Forced cooling could also be used with XD/SCFF cables using parallel water pipes, but this is uncommon.
- *Dynamic rating.* Cables almost always operate far below their thermal limits, and their conductor temperatures are much lower than allowable values. Therefore, the cables are capable of operating above their steady-state rating for significant periods without exceeding allowable temperatures. In many cases, the cables can even operate above traditional maximum temperatures without unduly decreasing cable life. Dynamic rating systems make this uprating methodology possible by determining the conductor temperature in real time based on measured parameters such as load, ambient earth temperature, and other conditions. A computer can record recent loading data, pipe, shield, or duct temperatures (and fluid temperature for an HPFF system), and ambient earth temperature, and calculates allowable ratings for future periods. The operator has the ability to determine the allowable loading for a certain period of time, determine the length of time permitted before temperature limits are exceeded, and so on. Dynamic ratings can permit ampacity increases of 20%–30%, depending upon operating conditions, with a relatively small investment in equipment.

14.2.11 Soil Thermal Properties and Controlled Backfill

The earth portion of the cable thermal circuit accounts for the greatest percentage of thermal resistance for buried cables—often more than half the total resistance. Native soil thermal resistivity can vary by an order of magnitude along a cable route, and it can vary by a factor of 3 at one location as a function of seasonal moisture content. Accurately characterizing thermal resistivities, developing dry out curves, and choosing the proper value to use in ampacity calculations are important parts of cable system design.

Soil testing is often done in the field (in situ) or laboratory (using samples) to determine the thermal characteristics of the soil in which the cables will be installed. A thermal property analyzer (TPA) is used for these types of measurements (Fig. 14-85). For a thermal resistance test, a thermal needle



FIGURE 14-85 Thermal property analyzer or “TPA.” (Courtesy of Geotherm, Inc.)

consisting of a heater and thermister is placed into the soil sample (Fig. 14-86). During the test, a constant heat output is applied to the thermal needle while the change in temperature is recorded; the slope of the recorded time-temperature curve is proportional to the soil thermal resistivity. This information is then used for ampacity calculations and to design the backfill materials to place in the cable trench.

In the laboratory, thermal dry-out curves may also be prepared that shows the effect of soil moisture content on thermal resistivity. Generally, as soils have increased moisture content, the thermal resistivity decreases (Fig. 14-87). Since cables produce heat, some drying should be considered when evaluating ampacities.

Significant ampacity increases can be achieved at reasonable cost by placing a controlled backfill with a low, stable thermal resistivity around the cables, ducts, or pipes. A good controlled backfill is characterized by low-thermal resistivity, less than $1 \text{ K}^\circ\text{-m/W}$, when completely dry, and a fairly flat curve of thermal resistivity versus moisture content. The proper material should be designed for each project using locally available materials, when possible, to provide the best installation and thermal characteristics at a reasonable cost. Well-graded sands or limestone screenings have been used since 1950s. Recently, many utilities have been installing FTB, which is a low thermal resistivity, free-flowing engineered material consisting of natural mineral aggregates, sands, cement, water, and a fluidizer (Fig. 14-88). It is delivered in ready-mix concrete trucks, and flows throughout the trench so there is no need for compaction.

14.2.12 Electrical Characteristics

Calculation of Electrical Parameters. Electrical characteristics for cables are calculated using various established methods. Resistance, capacitance, and inductance can be calculated using the industry



FIGURE 14-86 Thermal probe being inserted into an auger during geotechnical testing.

standard procedures for cable ampacity.⁷ Sequence impedances for cables can be approximated using various sources.^{23,24} Rigorous calculations for pipe cables are difficult because of the presence of steel (ferromagnetic) pipe; Ref. 24 has traditionally been considered the best approach available for pipe type, though it is known to be in error in many cases because of the great variability in line pipe permeability. For a typical single-core (XD, SCFF) transmission cable installations, a detailed procedure exists,²⁵ but does not easily lend itself to hand calculations. Induced sheath voltages may be calculated using the appropriate IEEE standard.⁴

Although surge impedance loading is never an issue for cables (unlike overhead lines) because cables ratings are always constrained by thermal limits, system studies sometimes require the surge impedance for modeling power systems. This can be calculated using the following formula where f is the power frequency, ϵ is the dielectric constant of the insulation, D_i is the diameter of the cable over the insulation, and D_c is the diameter of the cable conductor.

$$Z_s = \frac{f}{\sqrt{\epsilon}} \ln\left(\frac{D_i}{D_c}\right) \quad (14-99)$$

Fault current capability of a cable can be an issue, particularly in stiff power systems. The fault current capability of underground cables can be calculated assuming adiabatic conditions using the

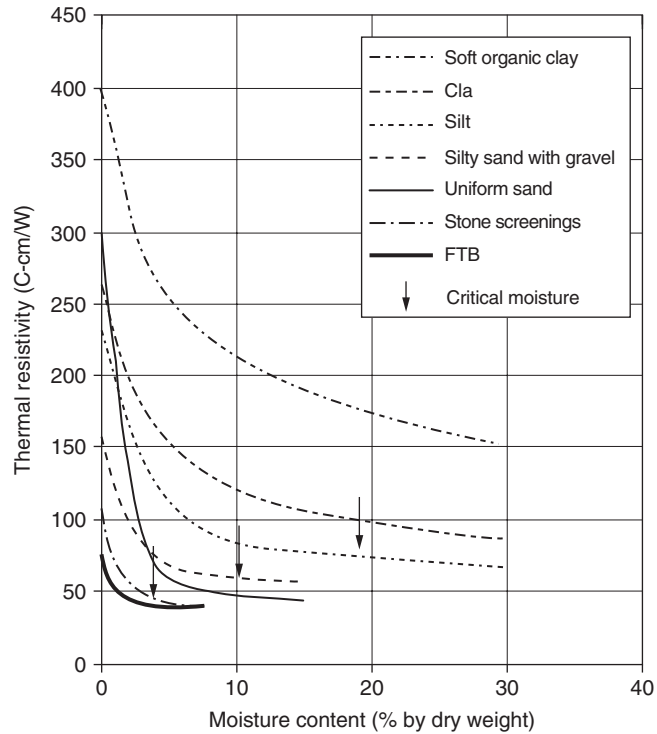


FIGURE 14-87 Soil thermal dry-out curves.

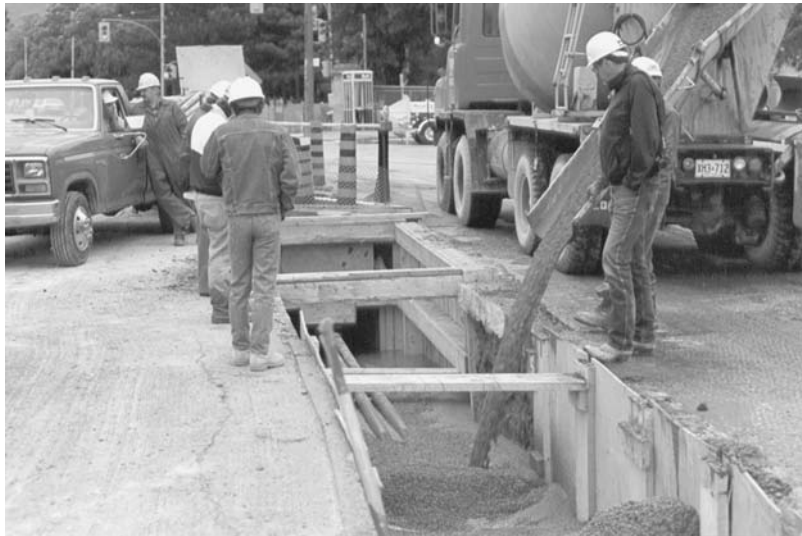


FIGURE 14-88 FTB being installed in a cable trench.

following equation where conductor area is in square millimeters, and time is in seconds (i.e., at 60 Hz, 30 cycle clearing time will be 0.5 s). T_1 is the temperature of the sheath or conductor prior to the fault in °C, T and k are material parameters for conductor or sheath material (see Table), and T_2 is the allowable maximum temperature for the insulation or jacket material (whichever is lower) in contact with the conductor or sheath. Conductor cross-sectional area is specified in square millimeters.

$$I_{SC} = (\text{Conductor Area}) \sqrt{\frac{k}{\text{time}} \ln \left(\frac{T_2 - T}{T_1 - T} \right)} \quad (14-100)$$

Conductor/Sheath Material	Constant, k	Inferred Temperature of Zero Resistance, T °C
Copper	50237	-234.5
Aluminum	21144	-228.0
Lead	1641	-236.5

Though polyethylene jackets are often used, many manufacturers allow higher shield/sheath temperatures than 150°C (some up to 250°C) based on experimental evaluation and the conservative adiabatic assumptions.

Insulation/Jacket Material	Temperature, T ₂ °C
High-density polyethylene	150
Cross-linked polyethylen	250
Polyvinyl chloride	150
Ethylene propylene rubber	250
Impregnated paper	150
Laminated paper-polypropylene	150

14.2.13 Magnetic Fields

Magnetic fields are generated by underground cables as a result of current flowing in the conductors of the cables. The intensity of magnetic fields is a function of conductor and shield currents, phase spacing, and distance from the source and can be calculated using the Biot-Savart Law as follows:

$$B = \frac{\mu_0 I}{4\pi} \int \frac{dS \times r}{r^2} = \frac{\mu_0 I}{2\pi r} \quad (14-101)$$

with μ_0 is the permeability of free space ($4\pi \times 10^{-7}$ Wb/m²), I is the conductor current in amperes, and r is the distance from the conductor in meters. Magnetic fields are reported in micro-tesla (μ T) or milli-Gauss (mG); 1 T is 10^4 G, so 1 mG is equal to 0.1 μ T.

Magnetic fields generated by 3-phase cable circuits must account for the individual cable phase current magnitude and phase angle and that the magnetic field is actually the resultant of the minor and major (real and imaginary) axes of the rotating elliptical magnetic field phasor. This can be done easily with the use of a computer for cables that do not have ferromagnetic elements such as the steel armor on submarine cables, the metal casing often used with directionally drilled cables, or the steel pipe around pipe-type cables. Cable systems with ferromagnetic components should be modeled using finite element software to account for the nonlinear nature of the problems and the variability in the permeability of steel with field intensity. CIGRE has developed procedures to calculate magnetic fields for cables with²⁶ (HPFF) and without²⁷ (XD, SCFF) ferromagnetic components; these methods use empirical relationships to account for the shielding effects of the iron-based shielding.

The importance of magnetic field management is a topic that varies depending largely on public perception of the issue. Some utilities have investigated various magnetic field management methods to find the best solution for a particular application.²⁸

14.2.14 Installation

XD and SCLF Cables. Installation of single-core transmission cables (SCLF and XD) requires that the cables either be directly buried or installed in conduits, although they are sometimes installed in troughs or mounted on the inside of tunnels. Preferably, the cables are installed direct buried—usually to a nominal depth of 1 m cover over the top cable—with center-line spacing of approximately 300 mm. Joint bay locations for direct buried cables or manholes for conduit systems are dictated by cable reel lengths (typically limited to 2600 ft or 800 m for large cables), local restrictions on the permissible length of open trench, or by maximum permitted sheath voltages. Depending upon the route plan and profile, allowable pulling tensions or sidewall pressures can limit spacing for cables installed in conduit. When cables are to be installed in conduits or pipes, it is important to consider the maximum pulling tension that may be encountered during the installation.²⁹ Fluid reservoirs for SCLF cables are spaced according to elevation changes or maximum transient hydraulic pressures during load cycling. Generally, each substation end has a set of reservoirs, although they may be placed in manholes as needed. Reference 30 gives details of a typical SCLF cable installation.

For conduit systems, the ducts are installed first and the cables pulled in and splicing done later (Fig. 14-89). This type of installation has benefits for urban environments where lengths of open trench must be limited and surface restoration must be done promptly. Many utilities install spare conduits so that additional cables or other utilities can be installed along the same conduit run.



FIGURE 14-89 Duct bank being backfilled.



FIGURE 14-90 Cable trench with final FTB layer installed.

Direct buried installations require that the trench be opened for an entire pull section. Depending on cable dimensions and reel limitations, this can be 500–800 m of trench. The trench frequently must have sheathing and bracing installed to prevent itself from collapsing. Where thermal sand or FTB will be used, a layer of the material is placed in the trench prior to placing cable rollers along the route. Then, the cable is pulled from one end to the other along the rollers using a winch. Once all cable phases have been pulled, thermal sand or FTB is placed around and above the cables (see Fig. 14-90). Additional backfill, a concrete cap, or marking tape can then be placed on top of the envelope around the cables before restoring surface conditions.

14.2.15 HPFF Cables

Pipe-type cables require much more complex installation procedures and specialized equipment than extruded-dielectric cables.^{23, 31} They are most commonly installed in city streets, where the narrow trench requirement, speed with which the pipe sections (approximately 12 m) can be installed, and ruggedness of the pipe offer advantages. Trench openings more than 200 m are preferred, and pipe installation can progress at several hundred feet per day, depending upon subsurface congestion, traffic conditions, and so on. The trench can be backfilled (often with a controlled backfill) as soon as a pipe section is placed, welded, the weld tested, coated, and the integrity of the pipe coating is checked. Manhole-to-manhole sections of 700–1000 m in length can be installed, vacuum/pressure tested, and pressurized with dry nitrogen until cable is installed later.

Cable is delivered to the site on large sealed steel reels and placed in a special trailer as shown in Fig. 14-91, lagging is removed from the reels, the three phases are brought together into a single pulling yoke, and the cable is pulled to the adjacent manhole. Characterizing the pulling tension is important to avoid damage to the cable or jamming of the cables in the pipe. One critical factor to consider is the coefficient of friction to use for the cable pipe and pulling rope.³² Pulling cables through the steel pipe is accomplished using a specialized pulling winch (see Fig. 14-92). Pressure-tight “night caps” are placed over the cable ends, the pipe is evacuated, and slightly pressurized with a nitrogen gas until splicing begins. A splicing trailer is placed over the manhole to provide a work area and maintain humidity control in the manhole. A 345-kV splice takes 5–7 days to complete.

Each termination takes about a day to assemble. Humidity-controlled enclosures are used for 345- and 230-kV cables, and occasionally for 138-kV cables. For both splices and terminations, it is important to maintain a dust-free and low-moisture environment during installation work.

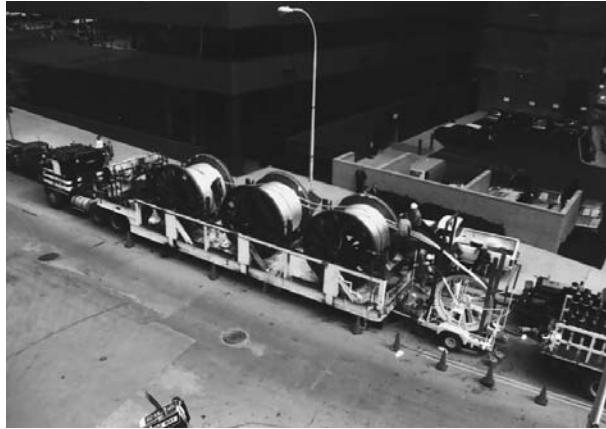


FIGURE 14-91 Reel trailer.

Pressurizing plants for HPLF cables are generally assembled in weatherproof enclosures at the manufacturing facility, shipped to the site and set in place on foundations (which may include a moat), where electrical and hydraulic connections are made. Before they are energized, the cables must be pressurized very slowly to prevent insulation damage and ensure that any minor amounts of gas in the cable are dissolved in the dielectric liquid.

14.2.16 GITL

Since the enclosures are rigid and diameters are large (e.g., 40 cm for a single phase of a 345-kV system), this cable type does not have as much flexibility as extruded-dielectric or pipe-type cables. Bends of more than a few degrees require a specially made elbow. Many systems have been installed directly buried, but most new designs call for installation in a trough that minimizes corrosion concerns and allows rapid access for maintenance. Care must be taken to properly design for thermal expansion of both the enclosure and the conductor.



FIGURE 14-92 Pulling winch trailer.



FIGURE 14-93 GITL installation. (Courtesy of CGIT/AZZ.)

The compressed-gas-insulated system is seldom installed in city streets; most applications are within substations or power plants, or on the utility right-of-way. Figure 14-93 shows a typical installation.

14.2.17 Special Considerations

Submarine Installations and Water Crossings. Short water crossings, less than 2 km, can be accomplished by horizontal directional drilling in many cases, and the cable system can be pulled into the casing pipe or directly into the bore in some instances. Traditional cut-and-cover installations are suitable where water bottom conditions and environmental considerations permit. Extruded-dielectric, pipe-type, and self-contained cables can be suitable for these short crossings.

Longer water crossings have sometimes been installed by laying the cables on the bottom, but the high incidence of ship anchor and trawler sled damage have caused almost all new installations to be buried by trenching, jetting, or plowing using special equipment to embed the cable below the water bottom. The cable laying ship, with special navigation and positioning equipment, pays off cable from a large turntable to an embedder that augers or water jets a trench for the cable to fall into during the laying operation (Fig. 14-94). The cable laying ship has the capacity to hold several miles of cable, depending on the size, which minimizes the number of splices that must be installed.

Thermal analysis of water-bottom material is important, especially for lake and river crossings where sediments tend to accumulate. Cables have failed because of drying out of sediment material around the cables, even though the water depth at the failure location was more than 10 m.

Self-contained liquid-filled cables have been used for major ac installations.^{33, 34} Extruded-dielectric cables are becoming more common for ac submarine cable installations.³⁵ Solid-type cables are commonly applied for long dc cable installations.³⁶ The 1990s and 2000s have seen a great deal of interest in submarine cable applications, worldwide.

Horizontal Directional Drilling (HDD). Horizontal directional drilling is becoming a common way to install cables under rivers, major highways, and other locations where trenching is not feasible.

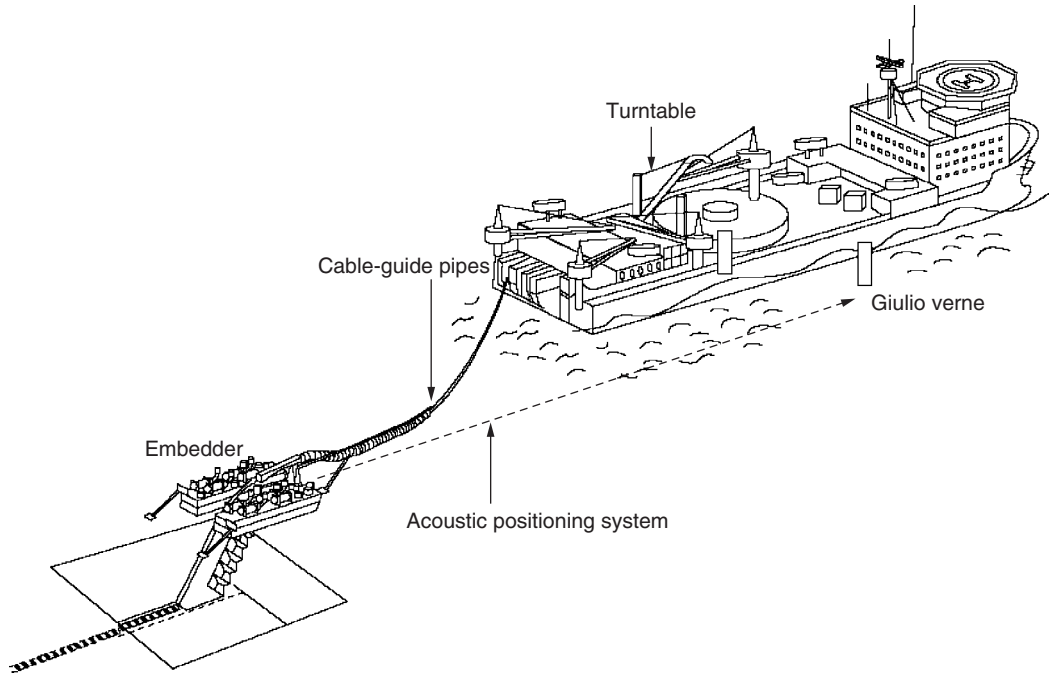


FIGURE 14-94 Cable laying ship and sea bottom embedder. (Courtesy of Prysmian.)

Drilling unit capabilities have increased, and prices have decreased, as the technology has matured. A recent installation in South Carolina successfully installed a pipe-type cable along a 7100 ft (2.2 km) HDD crossing. HDD installations are even being made in city streets, to avoid other utilities, to minimize traffic disruption, and to minimize the amount of contaminated soil that may be encountered.

Careful design work, including characterization of the materials along the drill path, must be performed so the proper drilling equipment can be selected to ensure a successful installation without loss of drilling fluid to the surface. Detailed thermal analysis is required to properly account for the 10–30 m burial depth. The utility must decide whether to install a casing pipe, either plastic or steel, which will require a larger bore and may decrease ampacity but will help ensure successful cable installation. Entry and exit angle requirements of 8–12 degrees can require a large setback for deep borings. Figure 14-95 shows a guided boring rig for a river crossing. Staging areas can be large, especially since casing pipe and ducts or cable pipe should be made up beforehand and installed without stopping—the drilling mud may begin to set up.

Since the cable will be inaccessible for repairs, utilities should consider stocking a section of spare cable that is the full length of the bore. For pipe-type cables, or three XD cables installed in a single duct or pipe, the spare cable must be 3 times the length of the bore. In the case of extruded cables, some utilities have installed a fourth cable in a spare duct, to speed reenergization in the event of cable failure.

14.2.18 Accessories

General. Although accessory cost is usually a small percentage of the total project cost, proper selection and application of accessories are extremely important for long-term reliability of underground cable systems. Historically, outages due to accessories are more frequent than those due to



FIGURE 14-95 Guided boring equipment for a river crossing.

problems in the cable itself. Much of the development activity, especially in extruded-dielectric cables, has been directed at simpler, easier-to-install, reliable splices, and terminations. (Note that a splice is the electrical reconstructing of the electrical insulation and shielding. A joint also includes housing, fluid supply, and so on.)

XD Cables. Different splice designs have been applied as the industry has matured, including taped splices, taped and molded splices, prefabricated and premolded splices, back-to-back SF_6 potheads, and a miniature extrusion facility set up in a manhole. In the late 1990s, premolded joints became the standard for field installation at most voltage levels. These joints were fully tested in the factory, and they required less assembly time in the field. In cross-bonded systems, the splice must accommodate an insulator in the outer shielding, to isolate electrically the shields/sheaths of adjacent cable sections.

Terminations are typically slip-on, with a dielectric liquid to fill any voids in the high-stress regions. The area above the liquid contains a compressible sponge, or simply an air space, to accommodate fluid expansion. Some designs require a small fluid reservoir for this purpose. Porcelain housings have traditionally been used, but polymer housings are becoming more common, especially for applications where the terminations are mounted directly on riser poles as shown in Fig. 14-96. Terminations are available for air installation, installation in single-phase SF_6 bus, and installation in 3-phase SF_6 bus.

Link boxes permit connections among the sheaths for grounding and cross bonding. The links must be removed when the cable jacket is tested electrically as part of routine maintenance. A sheath voltage limiter, resembling a distribution-class surge arrester, is often placed at the nongrounded end of a cable sheath to limit overvoltages, which might damage the jacket.



FIGURE 14-96 Terminations mounted on concrete risers.

HPFF Cable Splice. These types of cable splices are normally individual hand-taped assemblies which are bound together using an aluminum “spider” to maintain spacing and reduce flexing. They are contained in a 3- or 5-piece welded steel joint casing that can be 40 cm diameter and 3.5 m long. Trifurcating splices provide the transition from three cables in a steel pipe to individual cables in stainless-steel pipes rising up to a termination. Special “stop joints” are installed on high-pressure liquid-filled (HPLF) cables to minimize fluid loss in the event of a major leak, and to permit maintenance on the cable without draining large amounts of liquid.

Terminations (also called potheads) have paper “piano rolls” to help grade the electrical stress. Many 230-kV terminations and all 345-kV terminations have capacitor stacks inside the termination body to smoothly grade the electrical stress from ground to line potential. The HPLF terminations are pressurized with liquid from the cable pipe through filters and check valves that limit liquid loss in event of termination failure. HPGF terminations are typically just pressurized with nitrogen gas from the cable pipe, although some designs have a liquid-filled termination.

Pressurizing plants are sized to accommodate the maximum liquid demand and expulsion under all loading conditions. The plants contain a reservoir tank (typically 8000–40,000 L), pressurizing pumps, controls, and alarms. Since pressurization is critical to keep a line in service, backup pressurizing pumps are provided, sometimes including nitrogen-driven pumps that can operate during power outages. Emergency generators are supplied in some instances.

Cathodic protection is applied to protect the steel pipe in case the corrosion coating is damaged. The system consists of a rectifier to provide the -0.85 V needed to ensure that current flows from the earth to the pipe, plus a polarization cell (or solid-state equivalent) to provide a low-impedance path to earth for fault currents.

SCLF Cables. Normal joints are single-phase assemblies that have a special connector or ferrule to permit liquid flow through the conductor core. They are spliced in the same manner as a pipe-type splice and have a nonmagnetic lead, copper, or aluminum housing. Insulators are placed in the housing to permit cross bonding of the cable sheaths. Stop joints are placed every 1200–3000 m to isolate the liquid-supply sections. These joints may have to be placed closer together in areas with substantial elevation changes.

Terminations are very similar to those for pipe-type cables. Trifurcating joints are generally not required since almost all transmission-voltage self-contained cables are single-conductor design.

Liquid reservoirs are spaced along the circuit. Distances depend upon elevation changes, cable core diameter, and maximum allowable pressures. Typical spacings are 1500–5000 m. These reservoirs have alarms to indicate low liquid level or pressure. These alarms must be run back to the substation, typically in a separate communication duct, to notify operators of cable system problems.

GITL accessory requirements. These accessory requirements are minimal. Splices are an integral part of the assembly, and terminations are factory-made and attach to the cable in a similar manner as to a normal joint. The system contains alarms to warn of low pressure or high moisture content. Joints occur every 12–18 m (see Sec. 14.2.15) but are simple and straightforward. Expansion and contraction of the insulating gas is accommodated by allowing the pipe pressure to increase or decrease. Thermal-mechanical expansion of the aluminum bus is permitted by the use of bellows at bus connection points. The aluminum enclosure must be protected from corrosion using protective coatings and cathodic protection if the system is buried.

14.2.19 Manufacturing

Manufacturing of transmission cable should be done using quality materials and an environment free of contaminants. Impregnated-paper insulation technology has existed since the late 1800s and is the basis for substantial use of HPFF transmission cable in the United States. Extruded dielectrics, particularly cross-linked polyethylene (XLPE) insulation, have been used increasingly in recent years as the manufacturing technology to use this type of insulation up to 500 kV is developed.

Manufacturing requires that copper or aluminum wire be drawn and wrapped together for the required conductor cross section. Depending on the size of the conductor, the conductor may be

formed in segments—typically four for HPFF and XD cables and six for SCLF cables—that must be laid together. A binder tape may be applied to hold the segments together, and a taped shield is applied over the conductor on paper cables.

Insulation is applied over the conductor by drawing the conductor through an appropriate type of machine. For paper-insulated cables, the paper tapes are applied dry by wrapping the insulation around the conductor until sufficient insulation has been built up for the operating voltage. The paper cable is then heated under vacuum to remove moisture before dielectric liquid is applied in an impregnation tank. XD cables have insulation applied using a catenary, horizontal or vertical extrusion machine. A “triple extrusion head” is a modern approach to applying extruded insulation where the conductor screen (shield), insulation, and insulation screen (shield) are applied in one process.

After the insulation is applied and impregnated, HPFF cables are often wrapped with a Mylar tape intercalated with a metallic shielding tape. Then skid wires are applied helically over the tapes to prevent mechanical damage to the cables when the three phases are pulled into the pipe. The cable is placed onto shipping reels, and the reels are sealed and blanketed with dry nitrogen to limit gas and moisture ingress.

In single-core cables, bedding may be placed over the insulation screen to prevent damage to the cable during thermal expansion of the cable. If a wire shield is to be installed, this is normally put in direct contact with the outer insulation shield prior to applying the bedding layer. Additional bedding in SCLF cables or a water-swellable tape or powder in XD cables is then applied before a metallic sheath. The sheath is most commonly made of lead, corrugated stainless steel, copper, or aluminum, and can be applied in an extrusion or using a seam weld and a press. Finally, a jacket made of polyethylene or polyvinyl chloride is extruded over the sheath. The cable is placed on a cable reel with the cable ends sealed to prevent moisture from getting into the cable. Typically, a pulling eye is attached at the factory for use during installation.

14.2.20 Operation and Maintenance

Operation and maintenance requirements of underground transmission cables are small compared with most electrical power equipment and are essentially confined to the dielectric fluid-handling systems for HPFF and SCLF cables, the outer cable jacket or pipe protective coating, and the corrosion protection systems for HPFF cables.

Extruded dielectrics and SCLF transmission cables have an outer jacket typically constructed of polyethylene or polyvinyl chloride. The jacket is periodically tested to verify that there is no damage. Damage to the jacket may result in localized corrosion and unexpected circulating currents in the sheath that will cause I^2R losses in the sheath, lowering the effective ampacity or overheating the cable. If the cables are cross-bonded, the link boxes should be checked to be sure that the sheath voltage limiters are not damaged and there is good ground continuity for the local earthing (Fig. 14-97).

All SCLF and HPFF terminations and some XD terminations contain small amounts of dielectric liquid (200–600 L). The terminations should be inspected to be sure that there are no fluid leaks. In areas with high levels of air pollution, such as near the ocean, near unpaved roads, or in industrial areas, it is important that the outside surface of the terminations be cleaned to avoid surface tracking. Porcelain terminations should be free of cracks or other mechanical damage.

Dissolved gas analysis is a useful tool for HPFF and SCLF cables to determine the condition of a cable by examining the ratio of certain gases in the dielectric liquid. Field dissipation factor measurement can also be performed.³⁷ For both dissolved gas analysis and dissipation factor measurements, the trend with time rather than an absolute value is of interest for monitoring any degradation with time. Many utilities perform tests once per annum. Joints in locations susceptible to thermo-mechanical bending should be x-rayed every few years. Semiannual or quarterly dew-point readings should be taken on CGIT lines.

A few utilities have experienced problems with dielectric fluid leaks in HPFF cables caused by a combination of several factors including coating failure, cathodic protection problems, and stray currents in the earth. Monitoring of cathodic protection system performance and periodic testing of the pipe coating can limit the possibility of leaks, and leak detection and location using per-fluorocarbons tracers or leak detection wire buried along the cable pipe have been used with success.

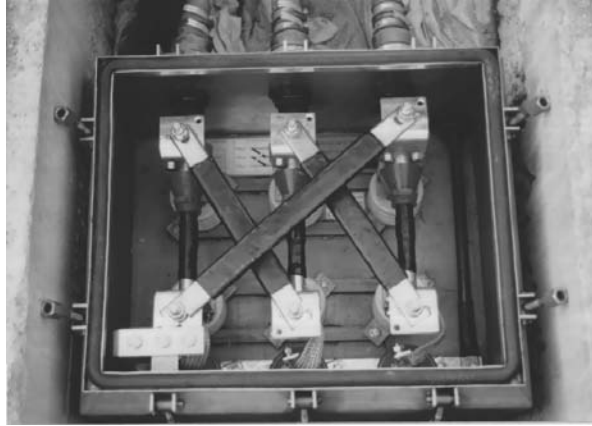


FIGURE 14-97 Cross-bonding box with links installed.

14.2.21 Fault Location

Although they are very uncommon, cable failures can be difficult to locate as compared to overhead lines where it is possible to visually inspect the entire line route. Locating cable faults requires the application of two types of techniques: terminal methods and tracer methods. Terminal methods are applied from one or the other end of the faulted cable and give an approximate location of a failure. Terminal methods include cable radar, bridge techniques, and time domain reflectometry. Tracer methods involve putting some type of signal on the faulted cable and then detecting changes in the signal when in close proximity to the fault location. Tracer techniques include tone sets, earth gradient, capacitive discharge (“thumping”), and magnetic pulse detection. Many times, the location of a failure is approximated with a terminal technique and then followed by a tracer technique precisely to locate the failure.

Pipe-type cable failures are particularly challenging. If fluid circulation is used on an HPFF cable, circulation should be stopped immediately once there is an indication of a failure to avoid contaminating the dielectric fluid. Since visible damage will generally not be apparent once the detection method has located the apparent fault location, the cable pipe must be x-rayed to determine if the exact location of the cable failure has been found. The liquid in the cable pipe must then be frozen on either side of the failure before the pipe can be cut and a repair initiated.

A good summary of classical fault location techniques can be found in Ref. 38. The IEEE Insulated Conductors Committee Working Group 12-48 is developing a guide for fault location.

14.2.22 Corrosion

Corrosion of underground cables can result from two phenomena; galvanic and electrolytic corrosion. Galvanic corrosion results from the electrochemical interaction of two or more materials, such as zinc and copper, with the level of galvanic action depending on the galvanic potential of the two materials. Steel, such as in a HPFF cable, can undergo corrosion from oxygen in acidic soil. Galvanic corrosion can be prevented by isolating the cable or pipe from other materials by using a protective coating or jacket. Pipe-type cables are often connected to a cathodic protection system where a negative voltage (relative to ground) is applied to the pipe using a rectifier and a polarization cell (or its solid-state equivalent is used) to provide a low-impedance path to ground for fault currents. Sacrificial anodes can also provide protection in the event the pipe-coating is damaged. Some utilities actively monitor the cathodic protection systems on the cable pipe to detect damage to the pipe coating as early as possible.

Electrolytic corrosion results from an externally imposed current leaving a conductive element where an anode zone is created. This might occur on the armor of a submarine cable. Protecting a cable from an electrolytic corrosion can be difficult because it is generally not possible to eliminate the source of the stray current that causes electrolytic corrosion. Instead, imposed cathodic current protection (ICCP) is used. In this scheme, anode beds are connected to the positive terminal of a rectifier, and the cable armor, for example, is connected to the negative terminal. Anode beds are placed along the cable to produce an imposed current on the cable armor. The level of stray currents will designate the current density, which must be produced by the ICCP system and anode beds in order to protect the cable.³⁹

14.2.23 Testing

There are various tests performed on underground cable systems during design, after manufacture, before and after installation (commissioning tests), and as part of maintenance. Various IEEE, IEC, AEIC, and ICEA standards have been developed that address this subject.

A manufacturer often performs a long-term “type test” prior to commercial production to prove the integrity of a cable and its accessories. Some purchasers of a cable system may also require that a type test be performed as part of their cable order, generally when a large cable system will be supplied or when a new set of accessories is being used with a cable for the first time.

As part of manufacturing, routine and sample tests are performed and verified by the purchaser’s representative to confirm that the cable was manufactured according to the designated specifications. Accessories also undergo routine tests and some purchasers choose to observe these tests or at least review completed test reports. Routine tests may include partial discharge (PD) testing, particularly on extruded cable systems, as well as capacitance, conductor resistance, dissipation factor ($\tan \delta$), and jacket integrity tests on extruded cables. Pipe-type cables on shipping reels may have the dew point and nitrogen pressure tested prior to shipping, and self-contained cables may have a check of dielectric fluid pressure rise to be sure that there is no air in the system. Some of these tests may be performed just prior to cable installation after cable reels are on site to be sure that the cable reels were not damaged during shipping.

After laying tests (commissioning tests) may include checks of conductor resistance, cable phasing, jacket integrity tests (on extruded or self-contained cables), a dc high-potential (“hi-pot”) test on paper insulated cables (only), as well as tests on dielectric fluids before filling cable pipes or pressure reservoirs. XLPE-insulated cables generally are subjected to an ac “soak” test (energized without carrying load) or may be subjected to some higher voltage if available within the connected substation. Very low-frequency (VLF) tests sets may be employed for testing XLPE cables although they have limited availability at the higher transmission voltages. Utilities are increasingly using variable frequency resonant test sets to apply multiples of rated voltage to an XLPE cable system where the higher voltage is not available locally; this has some advantages including very low-fault current energy to apply to a fault in the event a problem is detected during the test.

Tests during operation and maintenance include periodic jacket integrity tests, PD, dissipation factor measurements (mainly on paper-insulated cables), and the various methods used to locate cable faults as described earlier. Dielectric fluid testing is performed on paper cable to check for dissolved gases (dissolved gas analysis or “DGA”), which is often a good indicator of various problems with a cable system.

14.2.24 Future Developments

Research & Development (R&D) Efforts. R&D work on cable systems themselves has waned as the industry entered the twenty-first century. As some paper-insulated transmission cables reached 40 years of operation, studies were done in the mid 1990s to evaluate loss of life and end of life effects. Many cable manufacturers continue to push the upper voltage limits for cross-linked polyethylene cable systems with systems available up to 500 kV from several suppliers. Superconducting cables, which had been evaluated and set-aside in the 1970s, have moved past the prototype stage and are seeing limited commercial applications. Manufacturers are pursuing more practical ways of

offering HVDC cable systems, but most of this work relates to the connected converter stations rather than the cables themselves; one manufacturer offers a polymeric dc cable for this purpose.

Magnetic fields were once a critical issue for many utilities, but technical interest in this topic no longer seems to be a high priority. However, dynamic ratings and uprating methods are of great interest since these methods generally allow utilities to run their cable systems closer to the ultimate limit.

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